1.3.5 Statnett SF
Statnett SF was founded in 1992. The Ministry of Petroleum and Energy acts as its owner on behalf of the government, as specified in the Act of 30 August 1991 relating to state enterprises.
Statnett SF is responsible for the construction and operation of the central electricity grid. It owns about 87 per cent of the central grid, and operates the entire system. Statnett also has short- and long-term system responsibility. This means that it coordinates the operation of the entire Norwegian electricity supply system, and ensures that the amount of electricity generated is always equal to the amount consumed.
Statnett’s revenues are regulated by the NVE as part of its regulation of monopoly operations.

1.3.6 Enova SF
Enova SF was founded on 22 June 2001. Based in Trondheim, it is subordinate to the Ministry of Petroleum and Energy.
On 1 January 2002, Enova became responsible for government efforts to restructure energy production and use. This work had previously been split between the NVE and the electricity distribution utilities. Enova’s activities are financed from an Energy Fund, which receives the revenues generated by a levy of NOK 0.01 per kWh on the distribution tariff, and from ordinary appropriations over the central government budget. Its tasks are to promote more efficient energy use, the production of new renewable forms of energy, and environment-friendly uses of natural gas. Quantitative goals have been set for Enova’s activities.
tions, but a shorter utilisation period. A high-head power station is often excavated near the reservoirs used to regulate the volume of its water supply. Power station and reservoirs are connected by tunnels through the rock or pipes down the mountainside.

Power stations with an installed capacity of up to 10 MW are designated as small, and usually sub-divided into the following categories:
- micro (installed capacity below 0.1 MW)
- mini (installed capacity from 0.1-1 MW)
- small (installed capacity from 1-10 MW)

Small power stations are often installed on streams and small rivers without regulation reservoirs. Their output will then vary with the level of water flow.

2.1.1 Water inflow
Water inflow is the volume of water flowing from the entire catchment area of a river system into the reservoirs. A catchment area is the geographical area which collects the precipitation which runs into a particular river system. Useful inflow is the amount of water which can be used for hydropower generation.

Precipitation levels vary from one part of the country to another, between seasons, and between years. Precipitation is highest in coastal and central parts of western Norway. There is also a clear tendency for precipitation to increase with elevation above sea level. Mean annual precipitation is lowest in the upper Otta valley (300 mm) and in inland parts of Finnmark county (250 mm). The mean annual precipitation in much of western Norway is 3 000-3 500 mm.

Inflow is high during the spring thaw, but normally decreases during summer. High rainfall generally results in an increase before the onset of winter, when inflow is normally very low.

It also varies during the year, depending on local geographical and climatic conditions. The spring thaw is later in inland regions and in the mountains than near the coast and in lowland areas. In much of lowland eastern Norway, western Norway and Trøndelag, the rivers run highest during May. The highest water levels near the coast occur at the end of April, but are delayed until June or July in inland and upland regions. In northern Norway, discharge volumes reach a peak in June, or somewhat earlier in coastal areas.

![Water inflow and electricity output](image-url)

**Figure 2.1 Variations in water inflow and electricity output during a year**

*Source: Nord Pool*
Precipitation varies substantially from year to year and is more than twice as high in the wettest years as in the driest ones. From 1980 and 1993, precipitation in several years was high and ensured high water inflow for power generation. It was relatively low in 1993 and 1994 but very high in 1995 – resulting in record power generation. Inflow and electricity generation were considerably below normal levels in 1996. Since then, the level of inflow has been relatively high, and particularly so in 2000. Inflow in both 2002 and 2003 was below the normal level. However, variations through the year were considerable in 2002. From January-July, inflow was 89 TWh or 12 TWh above the normal level. However, the autumn was unusually dry with very low inflow. It was no more than 22 TWh, or 19 TWh below normal. Variations in actual power generation from year to year over the past decade can be attributed primarily to differences in inflow, since generating capacity increased very little.

In addition to variations in inflow, electricity demand fluctuates over the year and is much higher in winter than in summer. In fact, the pattern of demand – and thus the amount which must be generated – is generally the reverse of inflow variations. When inflow is high, output is often low – and vice versa. Figure 2.1 shows the relationship between mean output and useful inflow over a year. Consumption can also vary considerably between years because temperature changes affect the amount of electricity needed for heating.

2.1.2 Regulation reservoirs

The potential energy of water can be stored in regulation reservoirs constructed either in natural lakes or in artificial basins created by damming a river. Water is collected in the regulation reservoirs when inflow is high and consumption low. When inflow is low and consumption high, stored water can be drawn from the reservoirs and used to generate electricity. Regulation reservoirs are generally situated in sparsely populated areas, and usually at high altitudes in the mountains in order to make the fullest possible use of the head of water. The difference between the highest and lowest permitted water levels in a reservoir is stipulated in a watercourse regulation licence (rules for reservoir drawdown), which takes into account of such factors as topography and environmental considerations.

![Figure 2.2 Degree of filling of reservoirs in 2003](Source: Norwegian Water Resources and Energy Directorate)
Storing water in the summer for use in winter months, when the demand for power peaks, is known as seasonal regulation.

Dry- or multi-year regulation is made possible by large reservoirs which can store water in wet years for use in years when precipitation is low. Short-term regulation involves a daily or weekly filling and emptying cycle.

A reservoir’s energy capability is the amount of power which can be generated when it is full. Since 1980, the energy capability of Norway’s reservoirs has risen by just over 26.5 TWh. At 1 January 2004, the total energy capability was about 84.3 TWh, corresponding to just over two-thirds of annual electricity consumption. The degree of filling of the reservoirs is a measure of how much water (potential energy) they contain at any given time. Figure 2.2 shows changes in the degree of filling during 2003, and the minimum, median and maximum degree of filling in the 1990–2003 period, expressed as a percentage of the total energy capability of the reservoirs.

Normally, water will be drawn off during the autumn and winter when electricity demand is highest. Demand reaches its lowest level in spring and summer, and the reservoirs refill. Changes in the degree of filling of the reservoirs reflect variations in electricity generation and water inflow during the year.

An economic gain can be obtained by pumping water uphill to a reservoir with a greater head of water, because the potential energy of water increases in proportion to its head. If electricity prices are low, it may be profitable for operators to use power to move water to a reservoir at a higher altitude, so that the water can be used for generation when prices rise again.

### 2.1.3 Electricity generation

Norway now has a total installed capacity of about 27 700 MW at 581 hydropower stations larger than 1 MW. In addition come 255 MW from thermal and 100 MW from wind power stations. The mean annual generating capability of a hydropower station is calculated from its installed capacity and the expected annual inflow in a year of normal precipitation. Thirty years is the standard period used to calculate normal

---

**Figure 2.3 Installed capacity**

*Sources: Norwegian Water Resources and Energy Directorate and Statistics Norway*
Kvilldal power station in Rogaland county is Norway’s largest, with a maximum generating capacity of 1 240 MW. This corresponds to about 4.5 per cent of the Norwegian total. Table 2.3 shows the numbers and installed capacity of hydroelectric power stations in various size groups at 1 January 2002.

Electricity output in western and southern Norway and in Nordland county exceeds local consumption. In eastern Norway, on the other hand, electricity consumption is much higher than the amount generated in the region. This means that power must be transmitted from western and northern regions to the south and east of the country.

The flow of electric power between regions of Norway is also influenced by power exchange with Denmark, Sweden and Finland. Current transmission capacity from Norway to its neighbours is about 4 000 MW. The connections are used for both import and export of power (see Chapter 7). Power output was generally above average in the second half of the 1980s and the beginning of the 1990s because inflow was high. It was below the mean level in both 1996 and 1997. In 1998–2001, hydropower output was generally relatively high. Precipitation was above normal for several years in a row, with hydropower output high as a result. In 2000, a new generation record of

![Figure 2.4 Trends in hydropower output and mean annual generating capability](source)

Table 2.3 Hydropower stations in operation at 1 January 2004 by size and total installed capacity *

<table>
<thead>
<tr>
<th>MW</th>
<th>Number</th>
<th>Total installed capacity, MW</th>
<th>Mean annual output, GWh/year</th>
</tr>
</thead>
<tbody>
<tr>
<td>0–0.1</td>
<td>74</td>
<td>3</td>
<td>18</td>
</tr>
<tr>
<td>0.1–1</td>
<td>98</td>
<td>14</td>
<td>74</td>
</tr>
<tr>
<td>1–10</td>
<td>258</td>
<td>952</td>
<td>4 323</td>
</tr>
<tr>
<td>10–100</td>
<td>246</td>
<td>8 985</td>
<td>40 766</td>
</tr>
<tr>
<td>100–</td>
<td>77</td>
<td>17 764</td>
<td>73 326</td>
</tr>
</tbody>
</table>

* Figures for power stations below one MW are based on a study of micro and mini power stations connected to the grid, carried out by SKM Energy Consulting and completed in 2000.

Source: Norwegian Water Resources and Energy Directorate
143 TWh was set, while total output in 2001 was only slightly higher than in a normal year at 120.9 TWh. Figure 2.4 shows trends in mean annual generating capability and actual hydropower output in Norway from 1980 to 2001.

2.1.4 Hydropower potential

Norway’s hydropower potential is the amount of energy in its river systems which is technically and financially available to generate electricity, and was calculated to be 186.5 TWh/year at 1 January 2004. These calculations are based on 1970–99 the reference period. Figure 2.5 shows Norway’s hydropower potential at 1 January 2004. This includes river systems developed for hydropower, under development and protected. Other categories are rivers covered by licence applications, for which licences have been granted or refused, and for which prior notification of applications has been submitted.

Of Norway’s total hydropower potential, 36.5 TWh is in protected watercourses, and applications for development projects corresponding to 1.4 TWh have been refused. These two categories are therefore unavailable for development, leaving a potential of 30.2 TWh in river systems not protected from hydropower development.

At 1 January 2004, the developed mean annual generating capability was 118.4 TWh. In addition, projects with a capacity of 1.2 TWh were under construction, and the development of a further 1.4 TWh had been licensed.

Most hydropower projects were classified in the White Paper on a Master Plan for Water Resources. The various categories used in this Master Plan indicate the order in which river systems should be developed. Giving priority to the lowest-cost projects and those with the fewest conflicts of interest is considered important. The Master Plan is further discussed in Chapter 4.2.1.

Upgrading hydropower stations involves modernising them to use more of the potential energy of the water. In addition, operating costs can be reduced and operating reliability improved. The head loss can be reduced by widening water channels and increasing tunnel cross section, for instance. Utilisation rates can also be improved by using more modern turbine and generator technology.

Expansion involves major works such as transferring water from other catchment areas, enlarging existing regulation reservoirs or constructing new ones, increasing the head of water or expanding technical installations to increase the available power.
NOK 475 million to local authorities and NOK 122 million to central government in 2003.

Local authorities affected by hydroelectric development are also entitled to buy a proportion of the power generated. The licensee can be required to sell up to 10 per cent of the electricity generated to the local authorities concerned. If this exceeds general power consumption in the local authority, the county council is entitled to buy the surplus. The licensee can also be required to sell five per cent of the power generated to the central government, but the latter has not exercised this right so far. The price paid by the power recipient must correspond roughly to generating costs or the full cost of delivery. Deliveries under these provisions total about 8.5 TWh/year. Taxes, power supplied under licence terms and fees from power installations account for a large proportion of total revenues in local authorities which host major hydroelectric developments.

2.6 The role of the electricity supply sector in the Norwegian economy

The gross product in the electricity supply sector in 2003 was NOK 37.2 billion, or roughly three per cent of gross domestic product in mainland Norway.

Real capital in the electricity supply system amounted to NOK 170 billion in 2003, corresponding to 5.3 per cent of fixed real capital in mainland Norway.

Investment in the power supply sector totalled about NOK 6 billion in 2003. Gross investment in the sector has declined over the past 15 years, particularly for the construction of new power stations. Investment in the grid has also fallen. Figure 2.6 shows trends in gross investments in the electricity supply system since 1980.

Employment in the electricity supply sector rose steadily during the 1980s and stabilised after 1989. The number of people employed has declined in recent years. About 15 000 people worked in the electricity supply sector in 2003.

Figure 2.6 Gross investment in the electricity supply system. Fixed 2003 NOK

*Sources: Norwegian Water Resources and Energy Directorate, Ministry of Petroleum and Energy*
3.1. Factors influencing energy use trends

A country’s energy use and material living conditions are normally closely related. Generally speaking, energy use rises with economic growth because the need for energy increases as more goods and services are produced. Economic growth means higher household incomes which are devoted in part to expanding consumption, including the direct and indirect use of energy.

The effect of economic growth on energy use will depend on which sectors of the Norwegian economy are growing. Energy usage varies widely from one sector to another in terms of both energy mix and energy intensity in production.

Considerable developments have occurred with electrical products for private households and industry. Falling product prices combined with rising disposable incomes have made new products available to more people. Many products once confined to the few are now to be found in most homes.

Demographic factors such as population size, age structure, settlement patterns and the number and size of households have an impact on energy demand. Population growth leads to an increase in energy use because more houses, schools and commercial buildings are built, and these need heating and lighting. Population growth also results in higher consumption of goods and services produced with the aid of energy.

Energy use will be higher for a given number of people living in many small households rather than in fewer large households. Over the past few years, the number of Norwegian households has increased by more than would be expected from population growth alone.

Energy use also depends on energy prices. Higher energy prices boost production costs for industry as well as the cost to households of using electricity and other energy carriers. This usually constrains energy use.

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**Figure 3.1 Per capita energy use in OECD countries, 2002**

*Source: Energy balances of OECD countries, IEA/OECD Paris*
3.2 Trends in energy use

Per capita energy use in Norway is somewhat higher than the OECD average. See figure 3.1. However, the proportion of energy use accounted for by electricity is considerably higher than in other countries. The main reasons for the high proportion of electricity use are that Norway has had access to plentiful supplies of relatively cheap hydropower, and that government investment has focused on hydropower development. A large energy-intensive industrial sector has developed as a result, and electricity is widely used to heat buildings and water.

Net domestic energy use in Norway during 2003 came to 787 PJ, corresponding to 219 TWh. From 1980 to 2003, net domestic energy use increased by an average of 1.4 per cent per year. Figure 3.2 shows energy use by carrier and consumer category in 2003.

Stationary energy use is defined as net domestic energy use minus energy utilised for transport purposes. Stationary energy

**Gross and net energy use**

Gross energy use represents domestic production plus imports minus exports. When calculating gross consumption of petroleum products, adjustments are also made for changes in bunkers and stocks.

Net domestic energy use is defined as gross energy use minus the energy utilised to convert and transport energy ready for the end user, energy carriers used as raw materials, and transmission losses.
use in Norway came to 588 PJ in 2003, corresponding to 163 TWh. This was up by 3.4 per cent from the year before. Figure 3.3 shows trends in stationary energy use by energy carrier from 1980 to 2001.

Electricity is the most important Norwegian energy carrier. Stationary electricity consumption in 2003 totalled 103 TWh, corresponding to 372 PJ. Oil products, wood and waste (bioenergy) are the next most important stationary energy carriers in Norway. Stationary consumption of oil products in 2003 totalled 94 PJ, corresponding to 26 TWh, while consumption of various types of gas came to 21 PJ, corresponding to almost six TWh. Recorded use of bioenergy totalled 51 PJ, corresponding to 14 TWh. District heating contributed seven PJ, corresponding to the consumption of almost two TWh by end users – of which households and service sectors accounted for six PJ. In addition, some coal and coke are used.

A marked shift from oil products to electricity has taken place over the past 20 years.
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A marked shift from oil products to electricity has taken place over the past 20 years.
years, with consumption of the latter up by about 50 per cent since 1980. Stationary oil consumption has declined by about 65 per cent over the same period. Partly because of the effect of the water inflow shortfall on electricity supplies, however, consumption of heating oils increased relatively sharply from 2002 to 2003. A normalisation of conditions in the power market will probably lead to a readjustment of stationary oil consumption.

The latter experienced its sharpest decline up to the start of the 1990s, and has since fluctuated somewhat from year to year. Heavy heating oil has seen the biggest fall in consumption. See chapter 3.4.1. Bioenergy consumption has shown a rising trend since 1980.

The changeover from heating oils to electricity took place primarily up to the start of the 1990s. Figure 3.4 shows price trends for heating oil and electricity to households.
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Figure 3.5 Electricity consumption in households by purpose
*Source: Statistics Norway*

Figure 3.6 Residential heating methods in Norway
*Source: Statistics Norway*
That part of consumption used for technical purposes is called “electricity-specific”, and can only be met by this form of energy. A large number of electricity-specific products for operating technical equipment are found in all sectors. Most other electricity consumption is accounted for by space and water heating. No regular statistics on electricity consumption for heating are available. In its 1992 household survey, Statistics Norway looked how electricity was used in Norwegian households. This study estimated that space heating accounted for 41 per cent.

The consumer can use various energy carriers for heating purposes. The possibility of alternating between different heating methods is crucial to the reliability of a supply system based on hydropower. To be able to change energy carrier at short notice, consumers must have installed several types of heating equipment. Figure 3.6 shows trends in the use of the most important methods of residential heating in Norway since 1973. Of the dwellings with two or more heating systems in 1990, most used a combination of wood-burning stoves and electric radiators. This gives an indication of the possibilities for substituting one energy carrier with another at short notice.

3.3 Energy use by sector

Studies of the distribution of stationary energy use between different consumer groups usually distinguish between manufacturing and mining, private and public services and households. Manufacturing is usually sub-divided into energy-intensive manufacturing, the pulp and paper industry and other manufacturing. Figure 3.7 shows trends in stationary energy use by sector. Electricity accounts for about three quarters of total stationary energy use in Norway.

Growth in energy use over the past 20 years has been highest in the household and service sectors. Energy use has risen by 70 per cent in the private services sector and 25 per cent in households since 1980.

Stationary energy use in energy-intensive industry and the pulp and paper sector has increased by 39 per cent since 1980.

![Figure 3.7 Stationary energy use by sector](source: Energy accounts, Statistics Norway)
business and industry and in private households when necessary. Rapid switching between different energy carriers is possible in systems utilising combined oil/electric boilers.

Oil is the principal fuel used in Norwegian water-based central heating systems. Renewable energy sources, heat pumps and waste heat can also be used in such systems.

### 3.4.2 Biomass

Bioenergy can be produced by incinerating or fermenting biomass or by treating it chemically. Biomass includes firewood, black liquor\(^3\), bark and other forms of wood waste, and waste from households and industry used to provide district heating. Fuel such as gas, oil, pellets and briquettes can be produced from biomass.

Recorded use of bioenergy in 2003 totalled about 51 PJ, corresponding to 14 TWh. The pulp and paper industry used some 38 per cent of this, with black liquor accounting for about two thirds and bark for one third. Roughly six PJ/year of bark, chippings and other waste is processed to produce other energy carriers. Other industries used wood and other biofuels equivalent to about 48 per cent of total bioenergy use in 2003. Firewood used to provide heating accounts for a substantial proportion of this.

The extent to which biofuel is used and its applications depend on factors such as available supplies and their quality and emission standards. Manufacturing of paper and pulp and of wood and wood products requires large amounts of heat for various drying processes, so that the energy in wood waste such as bark and chippings can be used without further processing in large incineration plants. A proportion of the waste in large landfills can be incinerated, and the heat energy can be used directly or in thermal power generation.

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\(^3\) Black liquor is the residue from wood used to produce chemical pulp.
on. Biofuel used in households and in small incineration plants often requires more processing to be suitable for transport, storage and handling.

Processing of biofuel has increased in recent years. Biofuel in the form of pellets and briquettes is more suitable for storage, transport and use in automated incineration plants.

### 3.4.3 Electricity

The 1995 survey of living conditions by Statistics Norway and the Norwegian Building Research Institute showed that fitted and portable electric radiators were the most important source of heating in 58 per cent of dwellings. A major shift from heating oil to electricity as the primary source of heat occurred in 1973-95. See figure 3.6.

Over half the dwellings with only one source of heat use electricity for heating. In dwellings with two or more sources of heat, a combination of electricity and wood is most common.

Studies for the Norwegian Water Resources and Energy Directorate (NVE) show that rather more than half of all energy use in commercial buildings is for heating purposes, and that two thirds of the energy used for heating is electricity.

### 3.4.4 District heating

The technology used to supply hot water or steam to households, commercial buildings and other consumers from a central source is known as district heating. Heat transported through insulated pipes is mainly used for space heating and hot water.

District heating systems can utilise energy extracted from waste and sewage, or waste heat and gas from industrial sources which would otherwise be lost. Hot water or steam in district heating installations can also be produced using heat pumps, electricity, gas, oil, chippings or coal. About half of Norway’s net deliveries of district heating derive from waste incineration plants.

Preliminary figures for 2003 show that consumption of district heating was about seven PJ, or roughly two TWh. Some two-thirds is used in service sectors, while households and manufacturing/mining used about 15 per cent each.

Figure 3.9 Consumption of district heating by various consumer groups

*Source: Statistics Norway*
District heating in Oslo

The district heating system in Oslo is the largest in the country and accounts for about half the total in Norway. Figure 3.10 shows trends in district heating for Oslo.

The Viken Energinett company distributed and sold about one TWh of district heating in 2003. In the course of a year, production is split more or less evenly between waste incineration and oil/electricity. Year-on-year variations in whether oil or electricity is chosen depend on the relative prices of these energy carriers.

Development of the district heating system in central Oslo began in 1937, but only really got going in the early 1980s in order to utilise heat from two waste incineration plants. These are the main heat sources today. In addition, electric and oil-fired boilers are used to meet peak demand for power in winter. When the outdoor temperature is low, the hot water/steam is piped into the network at a temperature of about 120°C. It is distributed to individual customers from substations normally located in customer cellars, and is returned to the central installation at a temperature of about 70°C. About 750 large customers and 2,250 individual dwellings are linked to the district heating system.

Oslo’s district heating installations now meet about 15 per cent of its heating needs. These systems have been developed in the city centre and three other areas, and three of these areas have been linked together in a single network since 1998. The main campus of the University of Oslo and Ullevål University Hospital are two examples of large customers. The hospital’s boiler room is now used mainly to meet its special needs for steam, but it can also be used as part of the district heating system – either to help meet peak power demand or as a reserve source of heat. All the hospital’s heating needs have been met by district heating since the autumn of 1999. Most of the individual dwellings which use district heating are in one of Oslo’s newer residential areas, where each is equipped with district heating via an individual substation, and energy consumption is also metered individually.

By replacing small oil-fired boilers, district heating helps to eliminate emissions immediately above roof level in residential areas and the city centre. This helps to improve air quality in Oslo.

Figure 3.10 District heating in Oslo 1986–2001

Source: KanEnergi
### 4.1 Introduction

This chapter describes the legislative and political framework for the power sector. Chapter 10 discusses water resource management in more detail.

A developer must have a licence pursuant to the Watercourse Regulation Act to carry out regulatory measures or divert water in a watercourse. This Act also gives the licensee the authority to expropriate the necessary property and rights in order to carry out regulatory measures. The Industrial Concession Act specifies that anyone who acquires ownership or user rights to a waterfall must obtain a licence. Development of a waterfall and construction of a power station usually require an additional licence pursuant to the Water Resources Act. The Energy Act requires licensing of all installations to generate, transmit and distribute electricity, from power station to consumer. A licence pursuant to the Energy Act is also required to trade electricity.

The legislation mentioned above is of particular importance for the energy and water resources sector. Other general provisions relevant to the sector are discussed later in this chapter.

Figure 4.1 shows which legislation applies to the different parts of the Norwegian hydropower system, from impounding water in a regulation reservoir in the mountains until electricity is delivered to the consumer.

### 4.2 Special legal framework for hydropower development

When a watercourse is used for hydropower development, conflicts may arise between a number of user groups and environmental interests. It has therefore been necessary for the authorities to develop extensive legislation relating to hydropower, which lays down requirements for obtaining licences for various purposes. The most important elements in the framework for hydropower development are the protection plans for water resources, the Master Plan for Water Resources, the Industrial Concession Act, the Watercourse Regulation Act and the Water Resources Act. The water resource authorities are responsible for managing water resources within this framework.

The licensing authorities are the bodies responsible for processing licence applications and for issuing licences. They include the Storting, the government, the Ministry...
In cases where a licence is required pursuant to the Industrial Concession Act, the Watercourse Regulation Act or the Water Resources Act, the NVE is responsible for coordinating application procedures. Once a project has been approved in the Master Plan for Watercourses, the actual application process starts when the developer sends notification of the project to the NVE. This notification is deposited for public inspection and circulated to local authorities and organisations for comment.

The NVE, in consultation with the local authorities concerned and other authorities, then decides whether an environmental impact assessment (EIA) must be carried out in accordance with the provisions of the Planning and Building Act. Even if notification is not required pursuant to the Planning and Building Act, the consequences of the project must be described in detail as part of the licence application.

If notification is required pursuant to the Planning and Building Act, the NVE will determine the final content of the study programme after submitting this to the Ministry of the Environment. The authorities and
4.3 The Energy Act

The 1990 Energy Act establishes the organisational framework for Norway’s power supply system. It encourages competition in power generation and trading. By means of various licensing arrangements, the Act regulates the construction and operation of electrical installations, district heating systems, electricity trading, control of monopoly operations, foreign trade in power, metering, settlements and invoicing, the physical market for trade in power, system coordination, rationing, electricity supply quality, energy planning and contingency planning for power supplies. Together with certain other statutes, the Energy Act also implements the EU’s electricity directive (96/92). See chapter 9.1.1.

The authority to make decisions pursuant to the Energy Act has largely been delegated to the NVE. The most important exception is that the Ministry of Petroleum and Energy has retained the authority to issue electricity export and import permits.

The Ministry of Petroleum and Energy is the appeals instance for decisions made by the NVE pursuant to the Energy Act. As a general rule, the Ministry will therefore only consider matters involving an appeal against a licensing decision made by the NVE. The King in Council is the appeals instance for matters dealt with in the first instance by the Ministry, such as export and import licences.

4.3.1 Administrative procedures pursuant to the Energy Act

If an EIA pursuant to the Planning and Building Act is required for a project, the same procedures are followed both for projects licensed under the Energy Act and for those licensed under legislation relating to water resources (see figure 4.2).
Central government ownership is managed through the Statnett SF and Statkraft SF state enterprises. For a company to be organised as a state enterprise, the government must be the sole owner. The differences between state enterprises and limited companies are otherwise not great.

More and more energy utilities are being organised as groups. This applies to almost 48 per cent of all holders of trading licences. About 60 per cent of parent companies are themselves involved in activities which require licences. The others are pure holding companies.

At 1 January 2004, 46 groups had a total of 134 subsidiaries. Subsidiary companies which intend to engage in activities which require a licence must hold their own trading licences. The formation of groups accordingly increases the number of licensees.

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5.2 Organisation and restructuring of the power supply sector

5.2.1 Organisation
The power supply sector is organised in various ways around electricity generation, trading and transmission activities. Depending on which activity is being pursued, companies can be designated as generating, grid or trading enterprises, vertically-integrated utilities or industrial undertakings. In some cases, they are described collectively as energy utilities. Companies have also been established solely to negotiate power contracts.

Everyone supplying or trading electricity must hold a trading licence. Figure 5.2 shows the number of energy utilities which held such licences at 1 January 2004 by their type of activity. The overlapping circles indicate how far such utilities are involved in several types of activity. Seventy-six are engaged in electricity generation, trading, and grid management and operation, for instance, while 46 are only involved in grid management and operation. A total of 320 companies hold trading licences.

Figure 5.3 presents trends in the various operating categories during 1998-2003. This shows that the number of vertically-integrated utilities has declined, partly as a result of mergers which have formed larger vertically-integrated companies. The number of legal entities engaged solely in operations subject to competition has been rising since 1998, with the exception of 2001. For the first time, the number of such licensees in 2003 exceeded the total for vertically-integrated companies.
5.2.2 Restructuring the power industry
In response to the deregulation of the energy sector in Europe, a substantial restructuring of the power industry is taking place in most European countries, also across national borders.

Many local authorities and counties in Norway have sold holdings in power companies. At the same time, larger regional power companies have been established, partly by acquisition and partly through mergers. Examples are Lyse Energi, Agder Energi, BKK and Skagerrak Energi.

Statkraft has acquired a stake in several large Norwegian power companies, and in Sweden’s Sydkraft. Investment by Norwegian companies in other countries has otherwise been limited.
5.2.2 Restructuring the power industry
In response to the deregulation of the energy sector in Europe, a substantial restructuring of the power industry is taking place in most European countries, also across national borders.

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6.1 Introduction

Generation, transmission and sales are the three basic functions of the power supply system.

The transmission grid is often divided into three levels, as shown in Figure 6.1. The high-tension central grid constitutes the “motorway system” for power supply, linking generators with consumers in various parts of the country. It also embraces transmission lines to other countries. The central grid usually carries a voltage of 300–420 kV, but certain parts of the country have lines carrying 132 kV. Regional grids link the central and distribution grids. Most energy-intensive industries and generating companies are connected to the regional and central grids. Distribution grids are generally used to distribute power to end users – private households, services and industry. A distribution grid normally carries a voltage of up to 22 kV, but this is reduced to 220 V for supply to ordinary consumers. A number of small generating companies are connected to the local distribution grid. Power lines in the Norwegian grid, including overhead high- and low-voltage lines as well as underground and submarine cables, extend for roughly 300 000 km, or more than seven times the circumference of the Earth.

The construction of transmission grids is costly, but the average cost per kWh transmitted drops as the level of grid utilisation rises until capacity comes under pressure. This means it is socio-economically inefficient to build parallel transmission lines if the existing lines provide sufficient capacity. Parallel lines may also result in undesirable land use patterns and be unnecessarily intrusive. Grid management and operation have therefore been defined as a natural monopoly, and this sector has not been opened to competition.

The 1990 Energy Act with subsequent amendments provides the legal basis for regulating grid management and operation (regulation of monopoly operations). The Energy Act is discussed in more detail in Chapter 4.3.

Figure 6.1. The power supply system

The grids are drawn as circles to indicate that they form a meshed network. This means that if one line is inoperative, power can be supplied to customers using other parts of the grids. G stands for generation.
Transmission tariffs for consumption vary from one grid company to another. This is because natural conditions and thus the cost of distributing electricity to the customer differ widely around the country. Both difficult natural conditions and a dispersed settlement pattern can boost transmission costs. In addition, the efficiency of grid companies varies considerably. Inefficient operation of the grid also contributes to high transmission costs and thereby to higher tariffs.

Private households are connected to the lowest voltage level in the distribution grids. The transmission tariff or charge they pay normally consists only of a fixed component and an energy component. Figure 6.2 shows average transmission tariffs for private households in each county at 1 June 2004, including VAT but excluding electricity tax. The figures are based on an average annual electricity consumption of 20,000 kWh. The average transmission tariff for a household consuming that amount per year was NOK 0.303 per kWh at 1 January 2004, including VAT.

With effect from 1 January 2004, the grid companies took over responsibility for collecting the electricity tax through grid charges. This job was previously discharged by the electricity suppliers via their invoicing. The electricity tax has been set at NOK 0.0967 per KWh for 2004, and comes to NOK 0.12 per kWh when VAT is added. The change has not increased the total cost to customers.

In order to reduce differences between transmission tariffs for end users in different parts of the country, a new grant system was introduced in 2000. It is intended to reduce transmission tariffs for end users connected to distribution grids in parts of the country with the highest transmission costs. Funds are transferred to the appropriate grid companies, which are then required to reduce their tariffs.

Figure 6.2 Transmission tariffs for private households at 1 June 2004, converted to a consumption of 20,000 kWh per year and shown in NOK per kWh.

Source: Norwegian Water Resources and Energy Directorate
party to all contracts traded on the power exchange. In addition, Nord Pool Clearing offers clearing of standardised contracts traded off the exchange.

**Nord Pool turnover in 2003**
Activity was reduced in Nord Pool’s markets during 2003, primarily as a result of the tightness of electricity supplies in the early part of that year.

The volume traded in the physical market declined by about five per cent from 2002 to 2003. Traded volumes for 2003 and 2002 were 119 and 124 TWh respectively. On the other hand, the value of traded volumes in the physical market rose by about 34 per cent over the same period to reach about NOK 36 billion in 2003. This value increase reflected higher spot prices throughout the year.

A decline of about 46 per cent in traded volume from 2002 to 2003 was registered by the financial market. Trade volumes totalled 545 and 1 019 TWh in 2003 and 2002 respectively. The value of this volume declined from NOK 180 billion in 2002 to NOK 139 billion in 2003.

Clearing of both bilateral trades and in the financial market has increased substantially over recent years, but declined by about 43 per cent in 2003 compared with the year before. It amounted to 1 764 and 3 108 TWh in 2003 and 2002 respectively, corresponding to NOK 369 billion and NOK 434 billion.

7.2.2 Managing bottlenecks in the grid
Nord Pool Spot sets a system price for each hour which takes no account of any transmission restrictions in the Nordic grid. However, such restrictions may arise between geographical areas.

Restrictions in the Nordic transmission grid, often termed bottlenecks, are managed by specifying price areas on either side of the bottleneck. Nord Pool determines such price areas in addition to the system

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**Figure 7.1 Developments in the physical and financial markets and in clearing since 1996.**
*Source: Nord Pool*
All end users must pay a transmission tariff to the local grid company to which they are connected. See chapter 6.2.2. If transmission and electricity supply are handled by different companies which are not members of the same group, the end user will normally receive two invoices - one from the grid company and one from the electricity supplier. However, most end users buy their power from a company or a group which embraces both functions. They usually therefore receive only one invoice which specifies the transmission tariff and electricity price as separate items.

The electricity tax is charged on power regardless of whether the latter is generated domestically or imported, and stood at NOK 0.967 per kWh in 2004. See the presentation of taxes and fees in chapter 2.5.

Large customers normally have meters which measure electricity use by the hour, so that a precise settlement can be made. Smaller consumers receive invoices based on a predetermined load profile, but can opt to be metered by the hour.

Household customers can also choose between different types of contracts for purchasing electricity. The commonest kind is based on a variable price, which means that the supplier can change the price after notifying the customer. In the first quarter of 2004, 67.5 per cent of all households had such contracts. Elspot-based contracts, such as ones which charge the Elspot price plus a fixed mark-up, were held by 10.7 per cent. The remaining household customers had various types of fixed-price contracts. A fixed price, for example for one year, means that the supplier cannot alter the price during the contract period, even if market prices change. The percentage of households with such contracts has increased in recent years, largely as a result of electricity price developments in the winter of 2002–03, and stood at 28.1 per cent in the first quarter of 2004.

Figure 7.2 Electricity prices for households 1985–2003. NOK per kWh in fixed 2003 NOK
Source: Norwegian Water Resources and Energy Directorate
Some 24 per cent of household customers, including cabins and holiday homes, had a different electricity supplier than the main one for their area in the fourth quarter of 2003.

Figure 7.2 shows trends in average prices for households from 1985 to 2003. The electricity price and transmission tariff were separated in 1993. The figure also shows the total end user price, including VAT and electricity tax. Prices for private households were relatively stable from 1986 to 2001. However, the cold winter in 1995-1996, combined with low inflow in 1996, resulted in a sharp rise in wholesale prices which led in turn to an increase in prices charged to households. These accordingly rose from 1996 to 1997. Precipitation was above normal for every year in the 1997-2000 period, with relatively high hydropower output. This was reflected in a general decline in prices over the whole period. Inflow to the reservoirs declined substantially in the winter of 2002-03. This led to a considerable rise in household prices for many consumers. See appendix 2 on the 2002–03 dry year.

7.3 Price formation

Norwegian electricity prices are determined by supply and demand in the Nordic power market and to some extent by the market balance in countries outside this region. Figure 7.3 provides a simplified outline of how electricity generating costs in the Nordic region influence electricity prices. The rising curve shows the availability of power capacity in the Nordic region as short-term generating costs rise. The falling curve shows the demand for power in the Nordic region. Generating costs are lowest for hydropower and nuclear energy. Precipitation and inflow to reservoirs determine how much hydropower can be generated, and are therefore also important for the overall output potential and for prices. Generating costs are higher at thermal power facilities, such as coal- and gas-fired stations. Given the current level of demand, coal-based facilities often serve as the swing generator to balance the market, and therefore determine the price. In a year with average hydropower output, electricity prices will therefore be largely determined by the

![Figure 7.3 Principles for short-term variable costs of power generation in the Nordic region](https://example.com/figure7.3.png)

*Source: Ministry of Petroleum and Energy*
cost of generating electricity from coal. In periods of increased demand, power stations with higher generating costs – such as oil condensate or pure gas turbine units – will determine the price. These peak-load stations are used only to generate electricity for short periods at a time. In Figure 7.3, they would lie on the steeply rising part of the supply curve. Temperature and general economic activity are among the factors which help to determine demand.

Figure 7.4 shows variations in the nominal Elspot price for 1992–04.

7.4 International power trading

Norway was traditionally a net exporter of power. But it has been a net importer since the late 1990s because consumption continues to rise while hydropower development has been limited in recent times. In certain years, however, high precipitation and inflow to reservoirs mean that the hydropower utilities can help exports to exceed imports. Net Norwegian power exports in 2002 totalled 9.7 TWh, for instance, while net imports came to 7.8 TWh in the following year. Figure 7.5 shows imports and exports of power by Norway from 1970 to 2003.

International power trading is determined by generating and consumption patterns in each country, in addition to the capacity of the transmission grid linking countries and the conditions for its use. One basis for power trading is the opportunities it offers countries to derive mutual benefit from differences in national generating systems.

Exchanging power in this way is important for Norway because it reduces the country’s vulnerability to variations in precipitation and inflow and makes use of the regulatory capacity of hydropower. Good opportunities for power exchange moderate the need to maintain a large domestic reserve capacity as an insurance against dry years.

Most of the countries with connections to Norway base their power output largely on thermal sources – coal, oil, gas and...
nuclear. This normally ensures stable energy supplies. The opportunity to import electricity in dry years provides a reserve for the Norwegian system. In years when water inflow is good, the transmission grids make it possible to export power from Norway. In this way, opportunities for power exchange will damp down price fluctuations in the Norwegian energy supply system. In a closed Norwegian system, electricity prices would be much more sensitive to variations in climate.

Power exchange between Norway and other countries exploits the advantages of interconnecting hydro and thermal power systems. In countries based on thermal sources, power station capacity determines how much electricity can be generated, while the limiting factor in Norway today is the amount of energy available in the form of water in reservoirs. The energy sources used in thermal power countries – oil, coal, natural gas and uranium – can generally be acquired in whatever quantities are needed and accordingly impose no restrictions on output.

Building new thermal capacity to meet short-term peaks in demand in countries with thermal-based systems is expensive, and adjusting output up and down in existing generating facilities is both time-consuming and costly. But thermal power stations can deliver relatively inexpensive electricity outside peak consumption periods – in other words, at night and on weekends.

Capacity in Norway’s hydropower stations exceeds the level normally required to meet domestic daytime consumption. Output from such facilities can be adjusted up and down rapidly and at low cost to meet fluctuations in consumption or unexpected short-term changes in power supplies.

Interconnecting a hydropower-based system with ones based on thermal power also makes it possible to reduce the need for new power stations and multi-annual reservoirs in Norway. When the Norwegian electricity price rises sufficiently above the marginal cost of thermal power output, it becomes profitable for neighbouring countries to export to Norway. Conversely, it is profitable for Norway to export power when the price at home is lower than in neighbouring countries.

Norway has transmission connections with Sweden, Denmark, Finland and Rus-
The drop in inflow led to a substantial decline in hydropower output. For the Nordic region as a whole, this was about 96 TWh in the second half of 2002 – roughly seven TWh lower than in the same period of the year before. Hydropower output in the first half of 2003 was only 84 TWh, about 26 TWh below the same period of 2002.

Big adjustments in the Nordic market helped to reduce the impact of the inflow decline. These occurred without government intervention to deal with the position.

Four factors in particular were significant:
• hydropower reservoirs were very important as buffers between output and consumption
• spare thermal generating capacity in other Nordic countries was eventually taken into use
• electricity imports from countries outside the Nordic region eventually became substantial
• consumption of electricity declined, particularly because of a shift to other energy carriers.

The loss of hydropower output was offset to a great extent by increasing thermal power generation. Nordic oil-, gas- and coal-fired electricity output in the second half of 2002 totalled 45 TWh, about nine TWh higher than in the same period of the year before. These power sources accounted for about 57 TWh in the first half of 2003, up by 18 TWh from the same period of 2002.

Nuclear energy output in the autumn and winter of 2002-03 was roughly unchanged from the previous winter.

Net Nordic electricity imports increased gradually from the summer of 2002 until the end of the year, and totalled 4.6 TWh for the second half of 2002. This figure came to 10.2 TWh in the first half of 2003, as opposed to 0.8 TWh in the first half of the year before. Russia was a particular source of these Nordic imports.

Norway’s net exports were high until the beginning of October 2002, when they began to decline gradually. But the country remained a net exporter until the beginning of December. Throughout the winter and spring of 2003, net Norwegian electricity imports were substantial. Purchases from abroad were particularly high from mid-
March until the beginning of May. The power exchange fluctuated between net imports and exports during the summer of 2003. Taken as a whole, Norway had high net exports of more than six TWh in the second half of 2002. This was reversed to net imports on a corresponding scale during the first half of 2003.

Electricity prices reached very high levels as a result of the tightness of the power market, adding to costs for Norwegian industry and householders in the winter of 2002-03. Electricity bills became a very burdensome expense for some.

The spot price for electricity in 2002 averaged NOK 0.201 per kWh, but varied considerably over the year. Power prices were low during the first half, but the gradual tightening of supply during the second six months eventually yielded substantial increases. Towards the end of the year, prices rose sharply over a very short period. From 30 November 2002 to 31 January 2003, the Nordic power market was characterised by high and fluctuating electricity prices. The average daily spot price ranged in this period from about NOK 0.5 per kWh to roughly NOK 0.8 per kWh. At its peak, the average daily price reached NOK 0.831 per kWh. Prices also remained high during January 2003, when the electricity spot price averaged NOK 0.524 per kWh. And prices in the rest of the winter and spring of 2003 remained far above the normal level for recent years. The average price in the first half of 2003 was NOK 0.317 per kWh.

Nordic electricity consumption was two per cent higher in the second half of 2002 than in the same period of the year before. During the first half of 2003, it was 0.5 per cent lower than in the first six months of 2002. Total Nordic consumption from July 2002 to June 2003 came to 388 TWh, an increase of 0.7 per cent from the preceding 12-month period. The growth in consumption was highest in Finland, while Sweden and Denmark experienced a modest increase and Norway showed a decline.

Total electricity consumption in the second half of 2002 was roughly on a par with the same period of the year before. During the first half of 2003, it was lower than in January-June 2002. A particular decline in consumption compared with the
previous year was recorded from January to April 2003. Total consumption for the first half of 2003 was about four TWh lower than in the same period of 2002. A particular decline was recorded for power-intensive industry and electrical boilers.

Gross domestic consumption of electricity over the 12 months from July 2002 to June 2003 totalled 117 TWh, a decline of 3.8 TWh or roughly three per cent from the previous 12-month period.

The inflow decline put the Nordic power market to a hard test. A well-functioning power market helped Norway to emerge from the winter of 2002–03 without a supply crisis. The power system accordingly managed to cover an unusually dry autumn. Estimates indicate that conditions of this kind will recur every 100-200 years in Norway, 50–100 years in Sweden and 100–200 years for these two countries combined.
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Appendix 3

Transmission capacity in the Nordic region (MW)

- Total of existing lines
- Total of planned lines
- Total of existing submarine cables

[Map showing transmission capacity between countries such as Norway, Sweden, Denmark, Finland, Poland, Germany, Netherlands, and Russia.]