

Contract EIE/04/175/S07.38664

WORK PACKAGE 3

Deliverable 3.1

On the values of local electricity generation

by Jacob Klimstra
Wärtsilä Power Plants
Zwolle, The Netherlands

24th of April 2007

The sole responsibility for the content of this report lies with the author. It does not represent the opinion of the Community. The European Commission is not responsible for any use that may be made of the information contained therein.

Table of contents

1. Introduction

2 Electricity use in the EU-25 and its direct value for the economy

3 The costs and price of electricity

3.1 Generating costs

3.2 Transmission, distribution and system service costs

3.3 Taxes and levies

4 Matching electricity production with electricity demand

4.1 Demand fluctuations

4.2 Energy storage technologies

4.3 The dynamics of generating technologies

4.4 Supply reliability issues

4.5 Typical capacity issues of generators based on renewables

4.5.1 Wind power characteristics

4.5.2 Photo voltaic power

5 Environmental aspects

6 Energy savings from cogeneration

7 Summary of possible value aspects of local electricity generation

8 Detailed 5-country analysis

8.1 General aspects

8.2 The current state of electricity production

8.3 The impact of cogeneration on fuel use and electricity costs

8.4 Fuel costs for the nation because of electricity production

8.5 Electricity costs for the end user

8.6 Value aspects for electricity producers

8.7 Greenhouse gas emission aspects

8.8 The value of local generation for the government budget

8.9 The impact of local generation on security of supply

8.10 The effect of generating equipment costs on the national trade balance

9 Summarising conclusions

9.1 General conclusions

9.2 Specific conclusions from the five countries analysis

9.3 Typical conclusions related with the value issue

10 References

Appendix

1 Introduction

This report is deliverable number 1 of work package 3 of the ELEP project on local electricity production in the European Union. During the preparation of the project, the consortium members expressed the need for more insight into the ultimate values of local electricity generation for the various stake holders as well as for fuel efficiency, security of supply and emission reduction. Most project members had a background in electricity generation and supply issues, so that determining the values of local generation was seen as a labour intensive but achievable task. This was based on the reminiscence of the project members of integrated utilities with all the relevant information available if one had the proper contacts.

However, it appeared quickly that the recent transformation from the old integrated utilities to unbundled companies operating in an open market had drastically changed the situation. No longer was information about fuel efficiency, specific investment costs and maintenance and operation costs of existing generating equipment available for use outside these companies. Even the typical dynamic properties of the power plants were no longer disclosed because of competitiveness. The initial transparency that existed if one had the proper contacts had fully disappeared. Moreover, large-scale reorganisations in the electricity sector meant that many knowledgeable employees had left because of early retirement or other measures of redundancy. Next to that, the new commercial companies had no interest in carrying out unpaid assistance to outsiders, which further hampered the data acquisition process. Some data could still be acquired by using private contacts under the condition that the source and location were not revealed.

At the same time, rapidly increasing fuel prices based on scarcity and political issues changed the relatively stable fuel supply situation for electricity generation that existed until recently. Gas companies forced to operate on an open market became hesitant to make long-term contracts with a fixed price. Scarcity of gas and oil in the USA drove up their price so that coal and nuclear based power plants became in fashion again. A long-term reliable supply of natural gas from the major gas fields in Russia and Iran to Europe also became uncertain. China evolved into a consumer of so much coal for electricity generation that its own large resources will be fully converted into CO₂ by the year 2050. Consequently, China, by then even more powerful, will go to the rest of the world to satisfy its energy needs.

Europe, with its low indigenous sources of primary energy and its relatively high specific energy consumption per capita due to a high wealth level, will have to take drastic measures to ensure its energy supply. Electricity production uses now about 36% of the total primary energy supply to the EU, and it is expected that electricity consumption will have increased by 50% by the year 2030. That will further increase the role of electricity production as the major primary energy user. Local generation, due to its high energy efficiency, can be seen as one in the hybrid pallet of measures to improve efficiency, decrease emissions and increase security of supply.

The issues discussed in this report are also highly relevant for the rest of the world. The author has participated in a large number of conferences, workshops and courses to verify his results and to increase his knowledge of the various aspects. Active participation via presentations and panel memberships was very helpful in this and it confirmed the general interest in the subjects under investigation. Conference organisers were and are eager to include presentations and papers on the results of this Work Package 3 in their programs.

Retrospectively, the scope of this WP-3 task was too large and too diverse for the time and resources allocated. The drastically changed attitudes in the power sector were an unexpected restriction.

2. Electricity use in the EU-25 and its direct value for the economy

The average net electricity consumption in the EU-25 is only 12.5% of the total primary energy supply (TPES). Yet, 36% of TPES, the single largest fraction among the different sectors, goes into electricity generation. The reason for this substantial difference is that the mean value of the gross electrical efficiency of the power plants is only 41.5% while the own consumption by the sector as well as transmission and distribution losses reduce the net supply efficiency to only 34.6%. Electricity from hydro, wind and geothermal sources amounts to 12% of total electricity production in the EU-25. Without these renewables, the gross fuel efficiency of the power plants would only be 38.5%. Electricity generation has therefore a major impact on the use of primary energy in Europe.

Energy and electricity use per capita is not the same in every EU-25 member state. Figure 1 shows the TPES per capita for each member state. Luxembourg has with 438 GJ/annum by far the highest energy consumption per capita. The new member states Latvija and Malta have the lowest TPES/capita, about 90 GJ/annum. In Sverige and Suomi not only the TPES per capita is high, but the specific electricity use is viz. 14.7 and 15.9 MWh/capita, while the average EU-25 citizen uses 5.8 MWh/annum. These differences originate from the differences in wealth level, climate, economic activities and method of supplying a country with energy. In Belgium and The Netherlands, energy use per capita is also above the EU-25 average but electricity use is relatively low since these countries use primarily natural gas for space heating.

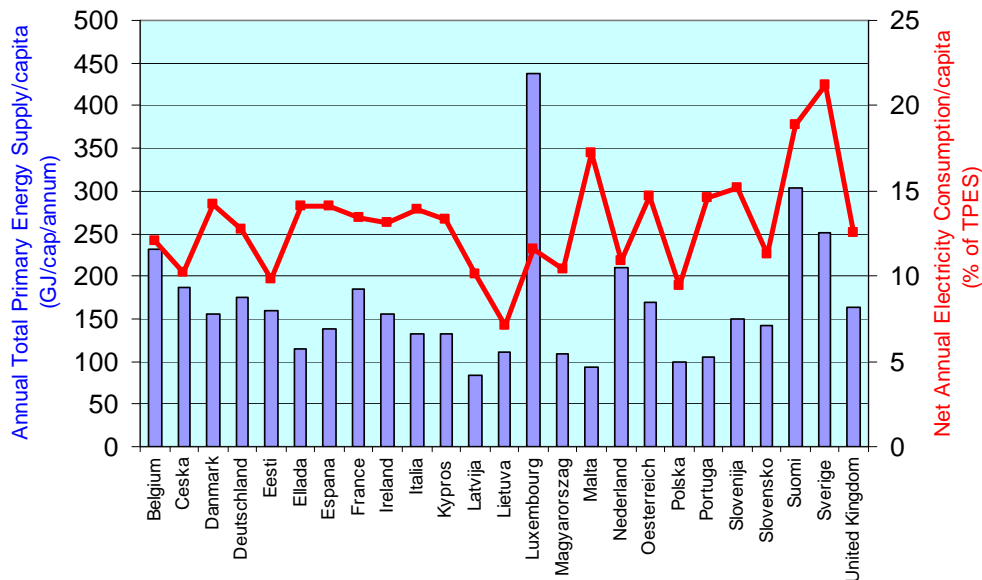


Figure 1: Annual total primary energy use per capita and net annual electricity use per capita as a percentage of TPES (data for 2004, source [1] and [2])

Statistical analysis of data from the International Energy Agency (IEA) [2] shows that TPES and electricity use in the world have a close to linear relationship with gross domestic product (GDP) expressed in purchase power parity (PPP). Energy use creates wealth, while wealth in turn creates demand for convenience and luxury use of energy. Figure 2 illustrates that a positive trend exist in the EU-25 between electricity use and wealth level, if GDP/capita serves as the wealth indicator. Sverige and Suomi are the outliers with a very high specific electricity use, while the domestic use by people in Luxembourg is lower than expected for this richest country of the EU-25. Yet, the total electricity use in Luxembourg clearly follows the trend of more use with a higher wealth level.

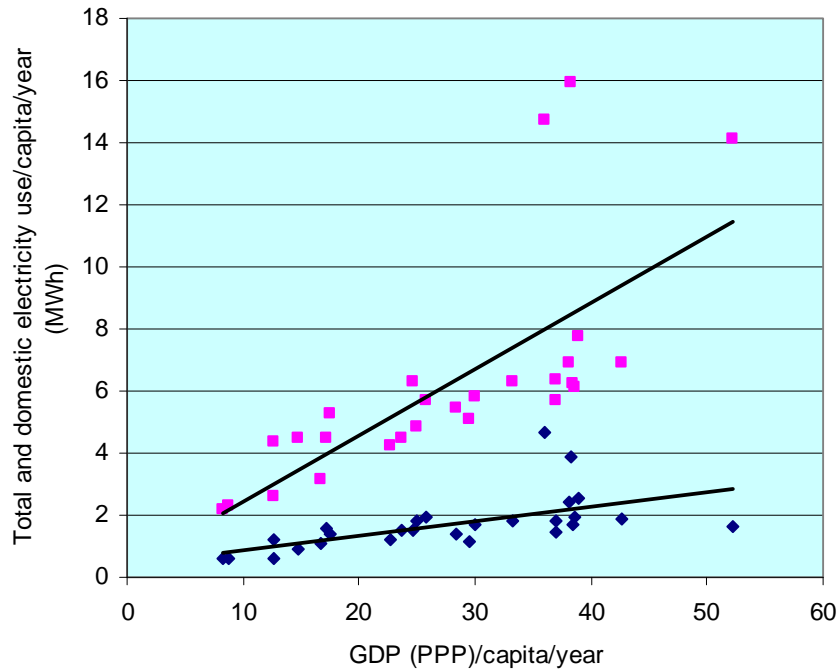


Figure 2: Total electricity use (purple) and domestic electricity use (blue) per person versus GDP (PPP) per person for the member states of the EU-25 in the year 2004.

The large inequality in wealth level over the EU-25 is already apparent in figure 2. Figure 3 gives the GDP/capita for the year 2004 of all 25 member states.

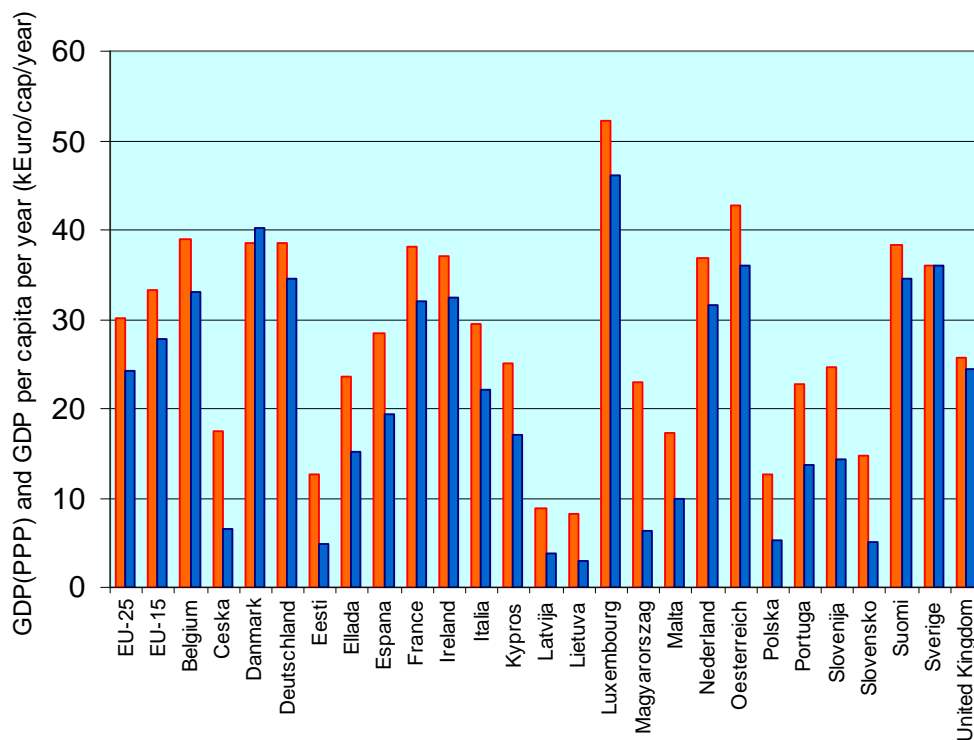


Figure 3: The gross domestic product per person in the EU-25 (red is PPP)

Industry is one of the activities that create wealth. Figure 4 shows how many Euros industry generates per kWh of electricity input. The € are expressed in absolute values as well as in PPP. Using the purchase power level of the € per country is still needed for comparisons because of the large differences in PPP between the old and the new member states. Apparently, Magyarország (Hungary) and Kypros (Cyprus) need relatively little electricity for their industrial production. Suomi and Luxembourg have a high specific electricity use in their industry since they generate only 1 € in GDP per kWh. That is half of what the EU-25 industry does on the average. The large countries Deutschland and France push up the average while Italia and España pull it down somewhat.

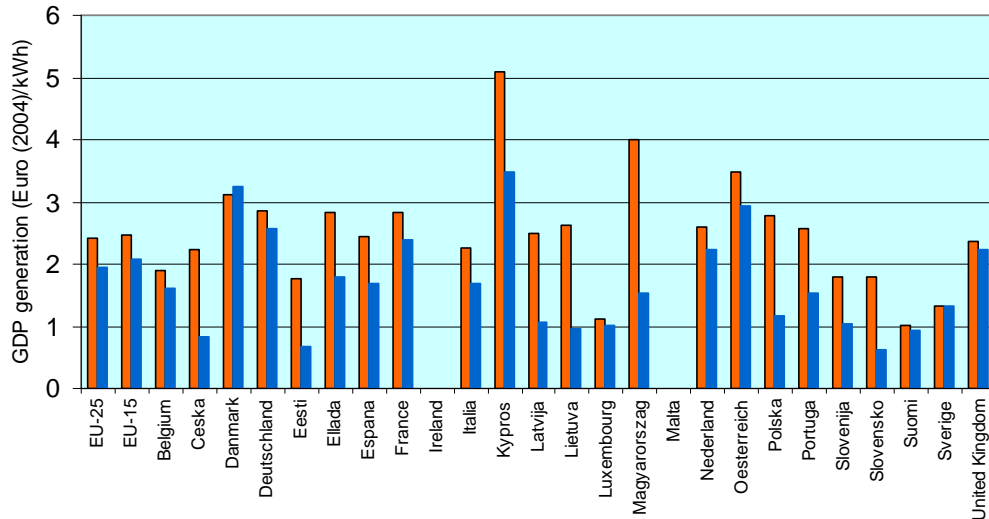


Figure 4: The added GDP value by industry in € (2004) per kWh electricity input (red is for PPP) for the EU-25 in the year 2004 [1]

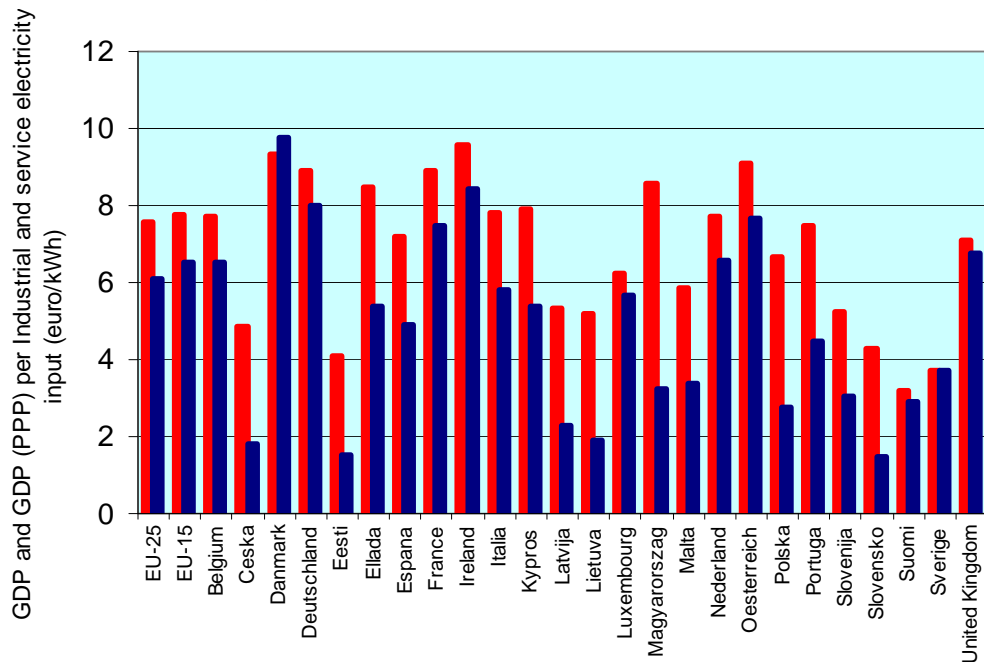


Figure 5: GDP generation (PPP in red) for the combined industry and service sector in the EU-25 for the year 2004 [1]

Industry often needs large amounts of electricity for its processes, e.g. for induction melting or paper drying, while the service sector uses electric energy in a more subtle way such as for computing and data transport. Hence, the 'GDP productivity' per unit of used electric energy is much higher for the service sector than for industry. Figure 5 shows that in the EU-25 the average GDP creation of services and industry combined is over 6 €/kWh, that is a factor 3 higher than for industry alone. The service sector is underdeveloped in most of the new member states. A larger service sector would definitely improve their GDP generation per kWh electricity input. Denmark and Ireland are clearly countries where a well developed service sector creates wealth with relatively little specific electricity input. Of the old member states, Suomi and Sverige are the most energy intensive. If the GDP generation per kWh by industry and services combined is expressed in PPP, the difference from country to country is a factor 3 at most. Suomi has the lowest performance and Ireland and Danmark the highest. If however PPP is not considered, most new member states perform a factor two to three worse than the EU-25 average.

In summary, large differences exist in electricity density of the economy between the industrial sector and the service sector and also from country to country. If electricity is treated as a continental commodity, the ten member states added to the EU-15 will find electricity use a much higher production cost factor than the old member states (apart from Suomi). Moreover, there is a clear relationship between wealth level and domestic electricity use. Although the service sector uses relatively little kWh/€, a reliable supply of electricity is crucial for this sector. The leverage of GDP creation by electricity in the service sector can easily reach 10 €/kWh. For a kWh price of 10 €cents, its average financial leverage is a factor 100. As an example, composing this report with a 100 W lap-top computer generates an average gross salary of 50 €/hour, which means a leverage of electricity use of about a factor 5000. Failure of electricity supply fully stops that process since a typewriter is no alternative for the intensive number crunching needed. In another example, for a vacuum cleaner of 1 kW a leverage of just a factor 10 exists, since a person can use a dustpan and brush instead, be it with human power of only 100 W. If heavy industry needs 1 kWh of 10 €cents to produce 1 € in GDP, a leverage of only 10 exists. So, the value of electricity in an economic process heavily depends on the typical underlying process. For the EU-25, we will use 2 €/kWh as a mean value for industries and 10 €/kWh for the service sector. This is based on the mean values of the data used to make figure 4 and 5.

3. The costs and price of electricity

In a fully unbundled and open electricity market, four main types of entity are involved in taking electric energy to the customer (see figure 6).

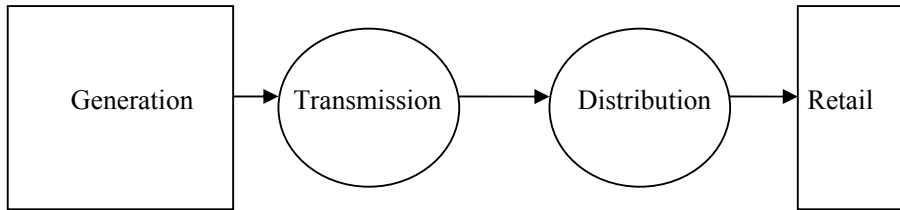


Figure 6: The four entities involved in electricity supply.

The generator transforms energy sources such as fossil fuel, nuclear energy, hydropower and wind into electric energy. The owner of the generator offers the electricity to be produced on the market. An independent Transmission System Operator (TSO) has to transport the electricity via very-high-voltage lines to distribution systems. Moreover, the TSO has to ensure that supply matches demand and that sufficient contingency capacity is available to compensate for failure of generators and transmission lines. The Distribution System Operator (DSO) has to ensure that the electricity can be transported to the end customers, who can buy electricity from the retail company (the ‘utility’). The DSO is also responsible for a proper voltage level at the customer’s connection. The retail company is responsible for contracts with and custody energy measurement for the customer. Next to this, there is the state that can charge the end customer and the four entities with value added tax, costs for operating permits and an energy use as well as emission levy. Ultimately, the end price for the customer can be more than four times the production costs. Competition by generators hardly affects the end price in such cases.

3.1 Generating costs

An electricity generating system, or power plant, is a technologically advanced installation with an investment price generally between 500 €/kW and 2500 €/kW, depending upon the technology and fuel(s) used. Fuel costs range between 1 €/GJ and 10 €/GJ, depending upon the fuel type and the country. Next to that, there are maintenance costs and operation costs that are primarily linked with the number of running hours and vary between 0.5 ¢cents/kWh and 1.5 ¢cents/kWh. The high specific investment and the risk of breakdowns make that insurance is generally inevitable. The premium can vary between 1 % and 5% of the investment. If the generating company has a contract with a direct customer or a TSO to deliver a certain capacity at a certain moment and fails to do so, fines have to be paid. If a generating company can offer contingency services or frequency stabilisation services, these services can be awarded by the TSO. Emission charges increasingly apply in countries that signed the Kyoto protocol (CO₂ emissions), or in case national air-quality levels (national emission ceilings) for NO_x and SO₂ cannot be met. CO₂ can be traded in a price range up to 73.5 €/ton and NO_x for up to 8 €/kg. If the generator has a facility to sell the heat released during the generating process to users, that will also generate money, between 3 and 8 €/GJ. Figure 7 summarises the mentioned financial inputs and outputs. Figure 7 can be seen as the economic model for a generator installation. The amounts mentioned have to some extent been derived from the questionnaires that were, partly, completed by WP3 partners (see the appendix).

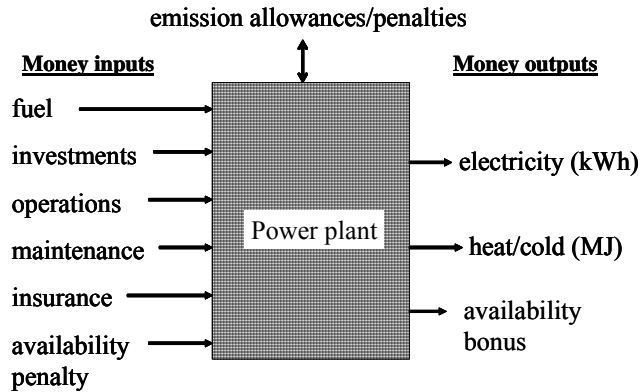


Figure 7: The financial inputs and outputs of an electricity generating installation.

3.1.1 Investment costs

The specific investment (€/kW) in a power plant heavily depends on the type of primary energy input. This applies for the traditional fossil fuels hard coal, lignite, oil and natural gas as well as for nuclear and renewables such as hydro, bio mass, wind energy and direct solar radiation. A power plant based on hydro needs a large investment in infrastructure such as a dam and space for water storage. Nuclear power plants require multiple measures to ensure safety. Natural-gas-fired power plants are relatively cheap because of the high energy density of the equipment (kW/kg or kW/m³) and because of little effort needed to clean up the exhaust gas. Coal-fired power plants require extensive flue-gas after treatment. In addition, not every generation technology has the same capability to follow the typical daily demand pattern for electricity of the end users.

In November 2006, Eurelectric organised a workshop on the future of electricity generation. Important aspects were competitiveness, security of supply and climate change. A presentation [ref] revealed the expected investments costs of power plants now, in 2030 and in 2050. Table 1 summarises some typical data on investments as derived from the ELEP questionnaires, additional confidential information from befriended competitors and from [3], [4], [5] and [6]. It will be clear that for real projects there can be much variation around the mean values since deviations will occur due to local boundary conditions as well as competitive effects. However, in this report we will use the reference values from table 1 for the comparative calculations.

Table 1: Summary of turn-key investment costs found for new power plants (2006)

Technology	Specific investment		
	Minimum (€/kW)	Maximum (€/kW)	Reference (€/kW)
Hard coal steam	900	1300	1200
Lignite steam	1000	1400	1300
Nuclear steam	1800	2700	2500
Natural gas combined cycle	400	1000	600
Coal gasification comb. c.	1400	1800	1600
Windmill onshore	800	1500	1200
Windmill offshore	1900	2300	2100
Solar photovoltaic	3500	7000	5000
Recip. engine cogen <20 MW	500	800	700
Recip. engine cogen < 1 MW	800	2000	900
Gas turbine cogen < 20 MW	590	1000	700
Gas turbine cogen < 1MW	1000	3000	1200
Biomass steam 5 MW	2750	3000	3000

Wind energy and solar energy require some additional remarks. Windmills have a utilisation factor ranging between 20% for on-shore installations and 30% for the best offshore locations. This is caused by the normal variations in local wind speed. It means that although the specific investment at nominal power of a windmill varies between 800 and 2200 €/kW, the investment per effective kW is much higher. The same applies for photovoltaic cells, where the amount of solar radiation depends on the time of the day and the season. An average utilisation factor of 17% is standard for photovoltaics.

In a liberated electricity market, an electricity generating company has to use the same financing method as any commercial company. For investments, enterprises use their own capital as well as loans from a bank. Ultimately, a company wants to make a higher profit on its capital than the interest rate a bank charges because of a desire for profits and risks of losing the invested capital. The averaged rate for capital is called the discount rate R :

$$R = \text{Loan fraction} * \text{bank interest rate} + \text{Own capital fraction} * \text{profit rate} \quad (1)$$

For a typical 30% own capital, a profit rate of 15% and a bank rate of 5%, the discount rate R is 8%.

The life of a power plant is limited, so the investment has to be depreciated within a number of years. Large power plants have a supposed life of 30 years. The annual cost rate, or fixed charge rate FCR , of an investment with a life of n years is:

$$FCR = R * (1+R)^n / ((1+R)^n - 1) \quad (2)$$

The FCR is then 8.9% for R is 8% and n is 30 years, while for n is just 15 years FCR will be 11.7%. In addition to the turn-key investment stated in table 1, one has to take into account the capital costs during construction and add these to the total investment. In a simple approach, the capital costs during construction are the FCR multiplied by 50% of the investment and by the construction duration in months divided by 12. The construction time of a modular, standardised, local unit can be three months while a nuclear power plant might take five years to build. This will add roughly 1% to the capital expenditure for a modular unit and 22% to that of the nuclear plant.

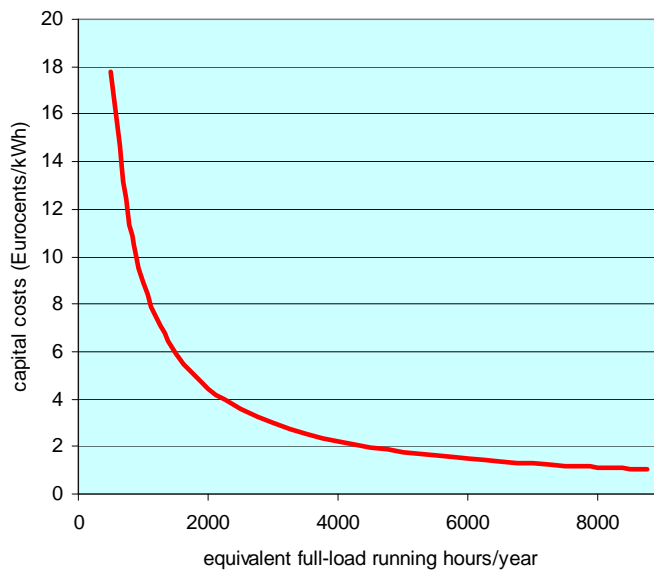


Figure 8: The effect of the equivalent full-load running hours/year (= utilisation factor or capacity factor) on the specific capital costs of electricity (presumptions: $R = 8\%$, specific investment = 1000 €/kW, $n = 30$ years)

Power plants can never run continuously during their life. The demand pattern for electricity is such that up to a factor three differences can exist between minimum demand and maximum demand. Therefore, some plants have to close down during weekends and during the night. Moreover, maintenance is required occasionally to keep the power plants efficient and reliable. Running during only a part of the life of the power plant increases the specific capital costs per kWh produced. The equivalent number of hours running on full load divided by 8760, i.e. the number of hours in a year, is called the utilisation factor or the capacity factor of a power plant. Figure 8 illustrates how the utilisation factor affects the specific capital costs of an installation with 1000 €/kW all-in investments, a discount rate of 8% and a life of 30 years. An offshore windmill with a specific investment of 2200 €/kW, a utilisation factor of 30% and an expected life of 20 years has specific capital costs of 8.7 eurocents/kWh.

3.1.2 Fuel costs

The demand for fuels continuously increases due to the rapid growth of the world's economies. The average energy intensity of the world economy in 2005 was 11 MJ/€ (PPP). An energy intensity of 11 MJ/€ means that on the average, one litre of oil equivalent or one cubic meter of natural gas is required to generate just 4 € in Gross Domestic Product. The basic price of these fuels currently ranges around 30 eurocents per litre for oil or per m³ for gas, which means that energy input into the economy has a leverage factor of 10 with respect to GDP. The energy intensity of the economy in developed countries has declined during the past decades, indicating a more effective application of energy for the creation of wealth. However, the easier ways of improving energy efficiency have been used now and the decrease in energy intensity tends to stop. If the current growth of the world's economy continues, demand for primary energy will most probably increase by between 50 and 60% in 25 years.

Oil has been the major energy provider during half a century. Oil is easy transportable with its high energy density of about 36 MJ/litre. Crude oil can be easily converted into petrol, diesel, lubricants, petrochemicals and fertilizer. Oil is a convenient space heating fuel in areas without natural gas. Oil is highly in demand, which is reflected in a crude oil price peaking around 70 US\$ per barrel in the recent past. Oil is by far the preferred fuel for road and mobile off-road applications. Currently, production has difficulty in meeting increasing demand. This makes oil generally too expensive for large-scale electricity generation. An exception is Heavy Fuel Oil (HFO), a rest product from refineries, which finds wide application for electricity generation in systems that are too small for large-scale power stations. Total oil use is expected to peak by the year 2020 with 100 million barrels per day or about 200 EJ/year [7]. Soothing comments that sufficient new resources will be discovered are not justified. According to [8] recent investigation have shown that Arctic oil fields contain just a quarter of the amount of oil initially predicted and that the USA will have to rely more on imports from Russia and Venezuela.

Natural gas is a very convenient fuel for electricity generation, from large-scale combined-cycle plants down to smaller scale reciprocating-engine-driven and micro-turbine-driven units. The reserves are such that gas is expected to be available about 20 years longer than oil. Gas use is projected to peak around the year 2040 with an annual consumption of 7500 Gm³ (225 EJ/year). Until the end of the 20th century, gas was primarily confined to markets that could be reached by pipelines. The longest pipeline (about 4500 km) transports gas from Siberia to Western Europe. However, gas liquefaction becomes more efficient and affordable and hence LNG tends to turn natural gas into a global commodity. Some countries however make indigenous gas available at low prices for their citizens and industries as well as for befriended countries. The gas price for the Atlantic countries is almost fully determined by the open market. Especially in the USA, demand for gas exceeds production and that is driving up the price which peaked around 8 € per GJ in 2006. The price of natural gas closely links to that of oil, partly because of its equivalent value for home heating but increasingly because of possibilities to convert gas into liquid fuels (GTL). In many countries, gas users have to pay an additional annual service fee related with the maximum required capacity.

Both Shell and Exxon are building GTL factories in Qatar with capacities of viz. 140000 and 170000 barrels a day. The gas used has to be considerably cheaper than the produced liquids per unit of energy because of the high capital investments for the installation and the low fuel efficiency of about 60% of the process. In conclusion, the price of gas and oil will show a high correlation. Reliance of the EU on imports of gas is expected to increase from 57% now to 84% by 2030 [9].

Coal is more abundantly available than oil and gas but less versatile. Moreover, it is less confined to certain areas in the world than oil and gas. It is more difficult to use than oil and gas while more efforts are required to clean up the exhaust gases. About 80% of the world coal production is used in power plants. The specific investment in a coal-fired power plant is considerably higher than that of a natural-gas-fuelled power plant (see table 1). As a result, the value of coal per unit of energy is lower than that of gas and oil. Coal-to-liquid conversion (CTL) is taking place in South Africa and China, with increasingly better returns of investment due to the high oil price. Global coal production is expected to peak between 2050 and 2060, at may be 250 EJ/year. The Chinese government expects that the Chinese coal resources, the country's main source of primary energy, are depleted around the year 2050. Ultimately, because of coal being one of the suitable fuels in power plants and because of the CTL process, the price of coal (and lignite) also links to that of gas and oil.

Nuclear fuel is very cheap, even compared with coal. The fuel costs are estimated to vary between 0.3 €/GJ and 1 €/GJ. That applies for the proven reserves of low-cost uranium, which are sufficient to satisfy demand for the next 50 years at the current consumption level. The long-term costs of storage of the used fuel are an uncertain factor. A renewed interest in nuclear energy might increase the demand for uranium in such a way that demand will outpace production. Price escalations might result, while the power plant owners are captive customers of a single fuel.

In summary, the price levels of the fossil fuels for power stations show a high correlation and will most probably have a medium-term relationship as given in figure 9. Medium term means for at least the next 5 to 10 years. The absolute price level will follow the costs of crude oil in proportion. The absolute prices in figure 9 apply for the end of the year 2006. This study will use the price levels in figure 9 as reference figures, since the author expects these to be close to reality. That does not mean that individual countries with government controlled energy companies cannot supply energy at lower price levels. In e.g. Indonesia, coal for power plants costs only 1 €/GJ and gas 1.8 to 2.1 €/GJ [10]. Even there, gas is twice as expensive than coal. Obviously, wind and solar energy are considered as free.

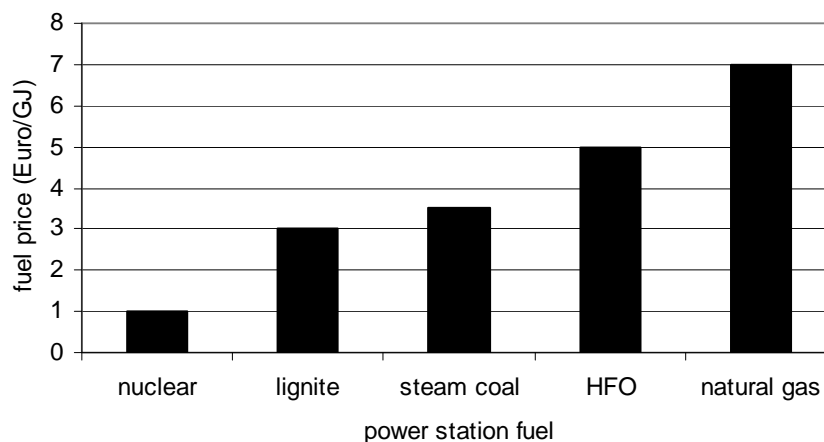


Figure 9: Mean price level relationship of the fuels for power stations.

3.1.3 Operation and maintenance costs

Every electricity generating unit needs attention and care by people. Large power plants have a fixed crew that normally works in shifts. The technical crew does the monitoring and control of the power plant. Next to that, people are involved with administration, security and building maintenance. Small generators, such as PV cells and wind mills, only need occasional attention and so do remotely controlled local generators fuelled by fossil or bio fuel. Technical systems do wear, and that is why regularly maintenance and occasionally repairs have to be carried out. Some costs, the fixed costs, occur independently of the number of running hours, such as those for allocated personnel and fire insurance. Other costs are variable, such as those arising from wearing parts and lubricating oil; these costs relate directly with the energy delivered. Both the fixed and the variable costs depend on the technology used for generating electricity. Table 2 summarises some values for the operation and maintenance costs as found from the ELEP questionnaires, suppliers and the literature [3]. The variation in the received variable O&M costs is quite high; this report will use the reference costs in the last column of table 2.

Table 2: Summary of found fixed and variable operation and maintenance costs

Technology	Fixed O&M costs		Variable O&M costs	
	per year	minimum	maximum	reference
	€/kW	\$/cent/kWh	\$/cent/kWh	\$/cent/kWh
Hard coal steam	16	0.2	0.74	0.5
Lignite steam	18	0.5	2.5	0.6
Nuclear steam	21	0.7	3.5	0.6
Nat. gas comb cycle	10	0.35	3	0.5
Coal gasif. cc	12 - 20	0.4	1.0	0.8
Windmill	13	0.3	1.6	0.4
Solar photovoltaic	8	0.1	1.2	0.6
Recip engine < 20 MW	15	0.7	1.3	0.5
Recip engine < 1MW	24	0.5	1.2	0.6
Gas turb cogen <20MW	7 - 10	0.3	0.8	0.4
Gas turb cogen < 1MW	20	1.5	1.5	1.5
Biomass	30	0.8	2	1.5

3.2 Transmission, distribution and system service costs

High-voltage transmission lines are quite costly to build although they have a long life of 40 to 50 years, natural disasters or acts of violence excepted. It is not easy to find detailed information about the costs per MWkm or MWhkm in the public domain. Specific investments between 250 and 500 €/MWkm for a typical stretch of 100 km have been found, albeit for a capacity of 2000 MW and 1500 MW. That equals between 25 and 59 €/kW for 100 km length, which is substantially cheaper than a power plant. [11] mentions 0.2 €/cents/kWh investments costs (12% capital costs, 30 years depreciation for a 50 miles stretch) of a 1500 MW, 500 kV line with a load factor of 65%. This is about the same tariff that TenneT, the TSO in Nederland, charges customers in a province for using an existing 150 kV transmission line (18.64 € per kW/year) [12].

In Suomi, the transmission costs are about 0.35 €/cents/kWh, in Deutschland and France about 0.65 €/cents/kWh and in the UK and Ellada about 0.85 cts/kWh. Considering the average price of electricity for large users in the EU of 6 €/cents/kWh [13], the high-voltage transmission costs can amount up to 10% of the electricity price.

Distribution system operators charge low-voltage customers up to 3 €/cents/kWh of distribution costs. These can be a factor two lower in case of off peak electricity. Next to that, a fixed annual amount for the maximum power or for the capacity of the connection has to be paid. The costs of this capacity charge are 5 to 10% of the energy costs in case of a constant annual

load. Consequently, the capacity charge can be equal to the energy costs in case of an annual load duration of just 500 hours. High-voltage users ($V > 10$ kV) pay substantially less for distribution costs than the 3 €cts/kWh. In this report, we will use 1.5 €cts/kWh for the average distribution costs as a default value.

The network operator is allowed to charge users of his system for the services provided. Among these services are frequency control and providing for contingency power. Typical service charges can amount to 0.1 €cts/kWh.

In Nederland, local generators receive compensation for avoided energy losses in the transmission and distribution grid. For the year 2006, this was 0.0364 cts/kWh, i.e. almost negligible compared to the total electricity costs. At first sight, local generators expect much more financial benefit because of claimed reductions in investments in grid expansions because of electricity generation close to the point of use. Moreover, they estimate that they are responsible for a substantial reduction in energy loss in the grid. The bulk of the grid losses occur however in extended low voltage grids where fitting in of economically attractive generators with a capacity of over 1 MW is not easy. Next to that, distribution grids have a voltage control and fault detection system that is based on on-directional current flows [14, 15]. So-called intelligent grids with many voltage and current measuring points might be an alternative but that is not cheap either. For the moment, one might say that reduction of low-voltage distribution costs is not really a benefit of distributed generation. May be microgenerators ($P \approx 1$ kW) might be an exception. Nevertheless, the reductions in investments in transmission systems and middle voltage and high voltage distribution can be substantial, especially if peak shaving by local generators improves the utilisation factor of the transport systems. Local generation might be an excellent instrument to solve transmission and distribution constraints, but in a fully unbundled system a TSO or DSO is not allowed to own and operate generating capacity and local generation is a matter of other investors, then.

3.3 Taxes and levies

Next to sales tax, or value added tax, governments charge energy users with energy levies and emission levies. Energy levies are intended to improve the effectiveness of energy use as well as to reduce consumption resulting in a higher security of supply. Emission levies can also be an instrument to reduce emission of undesired components such as greenhouse gases and species that decrease air-quality. Standard VAT rates for electricity in the EU-15 countries vary between 15 and 25%.

Figure 10 shows the price of domestic electricity before taxes as well as the final price per kWh. Without taxes, the price ranges between 6 and 13 Eurocents/kWh, but the end price including tax ranges between 7 and 24 Eurocents/kWh. The governments of the latest members of the EU-25 charge almost no tax, while citizens in Nederland and especially Danmark have to pay high taxes. According to the policy makers, the instrument of levies will help to optimise electricity use and to reduce consumption. Ultimately, that would have positive results for the economy. Currently, the result of high energy taxes is that a private customer has to pay a higher electricity bill. The customer will not see this as a benefit. The government derives income from the VAT and other levies. The average tax revenues from VAT on domestic electricity amounted to 0.5 % of the 2006 government budgets.

The differences in domestic electricity prices before tax partly stem from the fuel mix, from the age of the generating equipment and from the charges by the utility. It will be clear that a utility will also charge more in case of a higher salary level of its employees. Figure 11 gives the relationship between the height of the annual electricity bill per capita versus GDP (PPP) per capita. For the situation including taxes, Sverige (36, 729), Danmark (38.4, 470), Suomi (38.2, 429) and Kypros (25, 257) show an upward deviation from the trend, while Luxembourg (52.2, 264), Oesterreich (42.7, 267), Magyarorszag (23.0, 106) and Ellada (23.6, 107) show a negative deviation. Use of electricity for space heating in a cold climate is the main reason for the high bills in Suomi and Sverige. High taxation is the main reason for the high bills in Danmark. The relatively low electricity bills in Magyarorszag are caused by

extensive use of district heating. In Luxembourg, natural gas use for heating as well as low taxes result in relatively low bills.

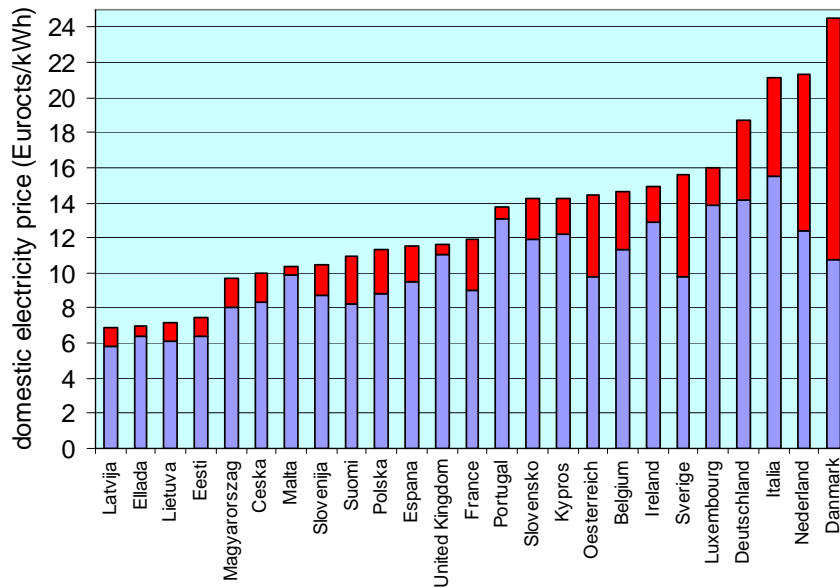


Figure 10: Domestic electricity prices in the EU-25 in 2006 (red = levies + taxes)

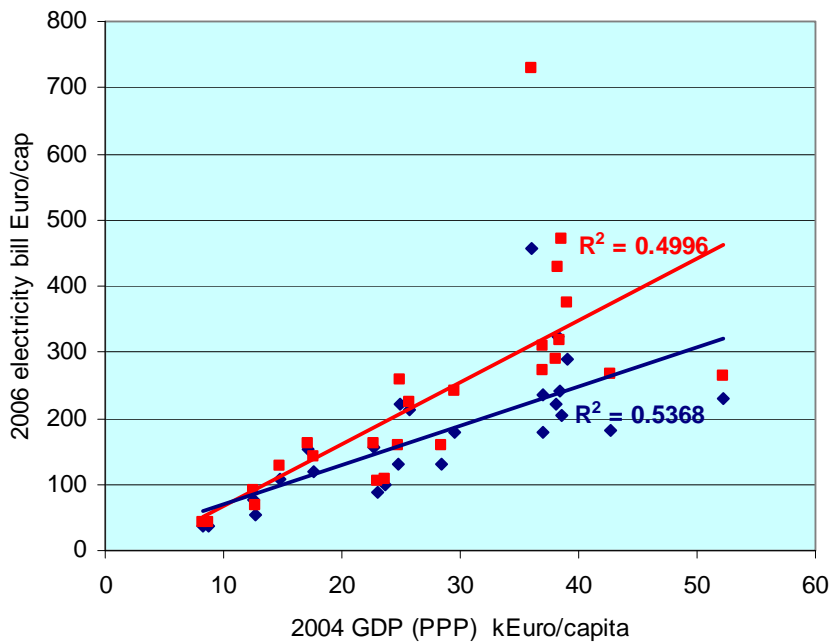


Figure 11: Correlation of the averaged annual electricity bill and GDP (PPP)/capita in the EU-25 countries, with (red) and without (blue) taxes.

Large-scale users pay substantially lower prices for electricity than domestic users. Reasons for that are substantially lower distribution costs, less taxes and competition that is more open. Governments fear high electricity prices for industries and commercials since that might hamper their competitiveness on the world market. Figure 12 gives the average electricity

prices for industrial applications, both with and without taxes. These prices closely approach the generating costs with some additions for transmission, distribution and system services. Electricity in Italia is expensive, since the bulk of the power stations use natural gas while oil-fuelled installations are often used for peaking power. In Kypros, close to 100% of electricity is produced with petroleum products. The Baltic states use relatively cheap gas from Russia while Poland uses primarily indigenous coal, peat and lignite. In France, nuclear power plants with relatively low capital costs generate the bulk of electricity.

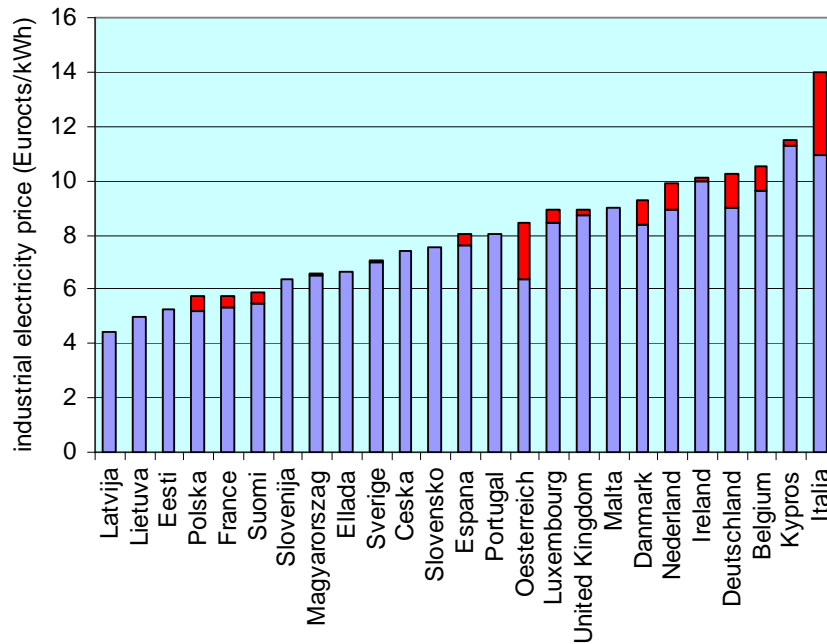


Figure 12: Electricity prices for industrial users in the EU-25 (year 2006).

Next to VAT, energy levies are supposed to be used to stimulate fuel conservation and emission reductions. Governments are expected to use the money to subsidise renewable generation and efficient technologies. Figure 13 compares the annual electricity levy income per country with the percentage of electricity generated by renewables, excluding large-scale hydro. Quite some countries without levies use biomass and wind power, but further the use of biomass is reasonably correlated with the levy level. Suomi is an exception; the abundant amount of biomass available, also as a rest product of the paper industry, makes it easily economic to use biomass. Nederland (46% levy on domestic electricity) had in 2004 relatively little wind power, also compared with the high levy, but the capacity is increasing now with 15 to 20% per year. Italy (23.8% levy) was also underperforming in 2004, but they have some large projects with bio oil since 2006. España charges only 5% levy, but it derives 5.6 % of its electricity from wind power. The benefits of biomass and wind power for electricity generation are reduced greenhouse gas emissions, but the end user does not receive any financial benefits as long as the fuel prices stay at the current level.

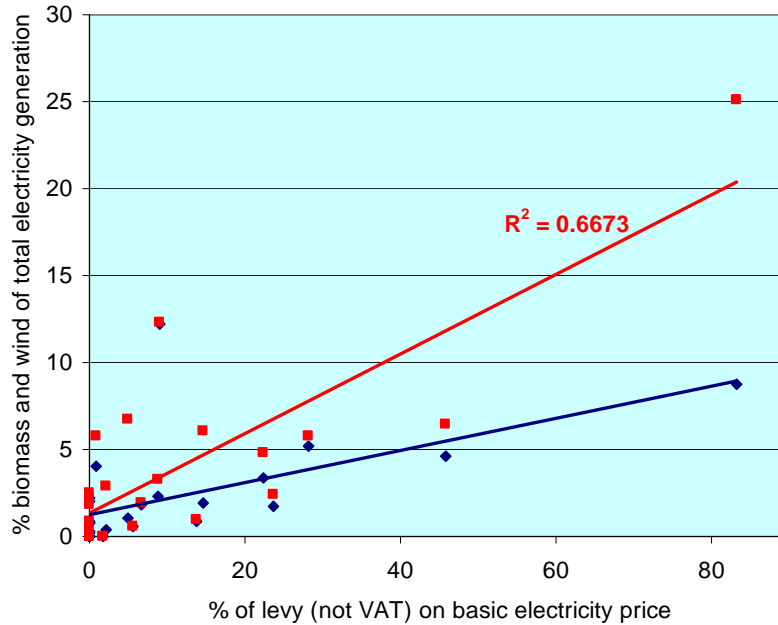


Figure 13: Relationship between % electricity derived from biomass (blue) and biomass + wind (red) in 2004 versus % of levy on the domestic electricity price before tax in 2006.

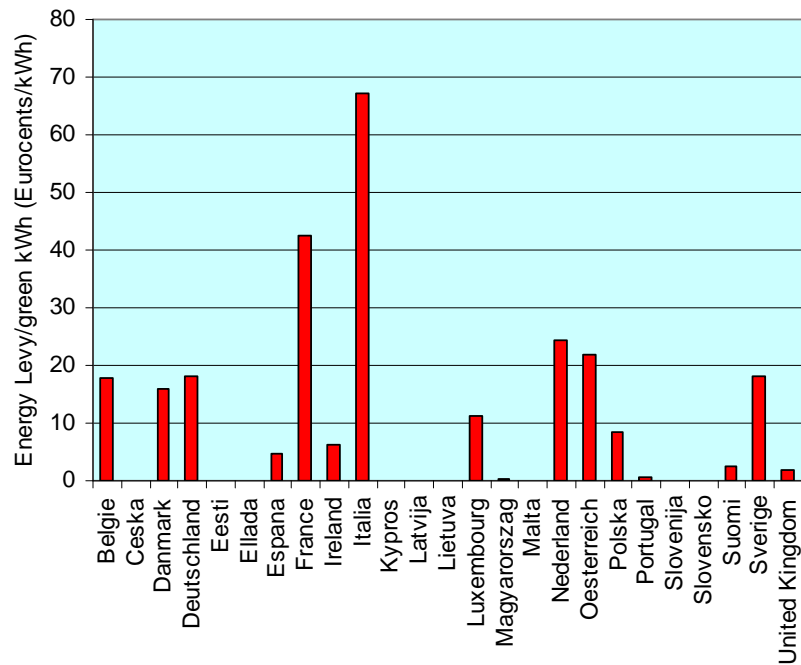


Figure 14: Total of energy levies per country (2006, excluding VAT) divided by green electricity production (wind, biomass + 30% of cogen) (data 2004).

One can get an indication how much contribution for energy savings a country can give if the energy levies of the domestic, service and industrial sector are added in a country, and divided by the total of the electricity produced by wind and bio power plus 30% of the electricity produced by cogeneration. We presume here that on the average 30% of the electricity from cogeneration can be considered as green. In some countries, a substantial amount of the fuels

for cogeneration stems from renewables, such as in Suomi (44.5%), Sverige (61.2%) and Portugal (38.3%) but the data in figure 14 have not been corrected for the fact that a generator can run on renewables and be a cogenerator at the same time. No country is known where more than 10 Eurocents/kWh compensation is given for green electricity, apart from Germany, where electricity from photo voltaic systems receive 50 €cts/kWh. Consequently, energy levies are an additional source of income for at least eight governments in the EU-25, or in other words an additional tax. VAT is also charged on the energy levy. Therefore, quite a number of governments will not benefit in this respect from lower electricity prices and from energy savings, since they will lose income.

An indirect subsidy for green energy can arise from the fact that in e.g. Nederland green investments are exempt from capital tax up to € 52000/citizen. That saves the investor up to 624 € tax money per year. Moreover, such investments are indirectly subsidised via a 1.3% additional tax reduction, i.e. a maximum of € 676. The total of green investments is currently 3.6 billion €, or 90 million € tax reduction. This is just 6.7% of the energy tax on electricity for households only, or close to negligible. However, the annual yield of green investments is about 2.25%. This is positive for green electricity producers since they can borrow money at a reduced rate.

4 Matching electricity production with electricity demand

4.1 Demand fluctuations

The demand for electricity varies during the day, the week and the year. Figure 15 illustrates a typical demand pattern of a weekday in an area of a typical West-European country. Between 2 am and 6 am, most activities come to a halt, followed by a rapid rise in electricity demand when people prepare to go to work and activities will start up. From 8 am till 4 pm, demand is fairly constant but in the wintertime, another sharp rise starts after 4 pm because people return home and switch on lights and appliances. In the summertime, less electricity is needed for lighting and for heating. The increase in domestic demand from 4 pm is initially not compensated by a reduced consumption by work-related activities, especially in the wintertime.

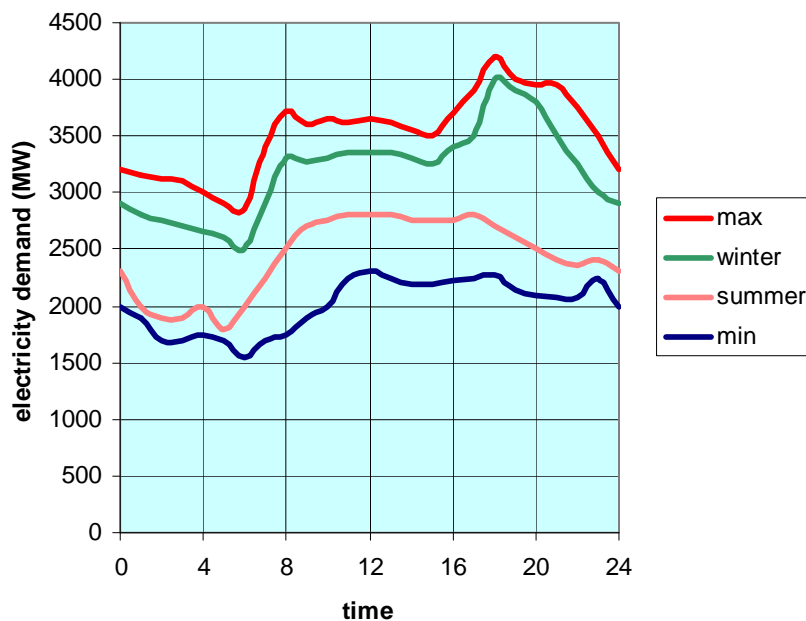


Figure 15: Example of a typical demand pattern of weekdays in Western Europe [16].

Countries in warmer areas traditionally show a demand peak at noon due to electrical cooling, especially in the summer. This is also changing nowadays towards a peak after 5 pm when people start to return home and switch on air-conditioning and cooking appliances. Figure 16 illustrates the case for Portugal.

The sharp rise in demand starting just before 8 am as well as the peak from 4 to 9 pm are a challenge for the power sector. A modern coal-fired power plant can only increase its output by about 3% of its nominal power per minute. In weekends, the demand is much lower than during weekdays. Especially in Northern and Western European countries, demand is much lower in summer than in winter and that can be exploited by carrying out maintenance during the summer. In hotter climates, that solution does not really apply. Figures 15 and 16 clearly show that not all generating capacity can run at full load all the time and many generators have to be switched off in times of low demand.

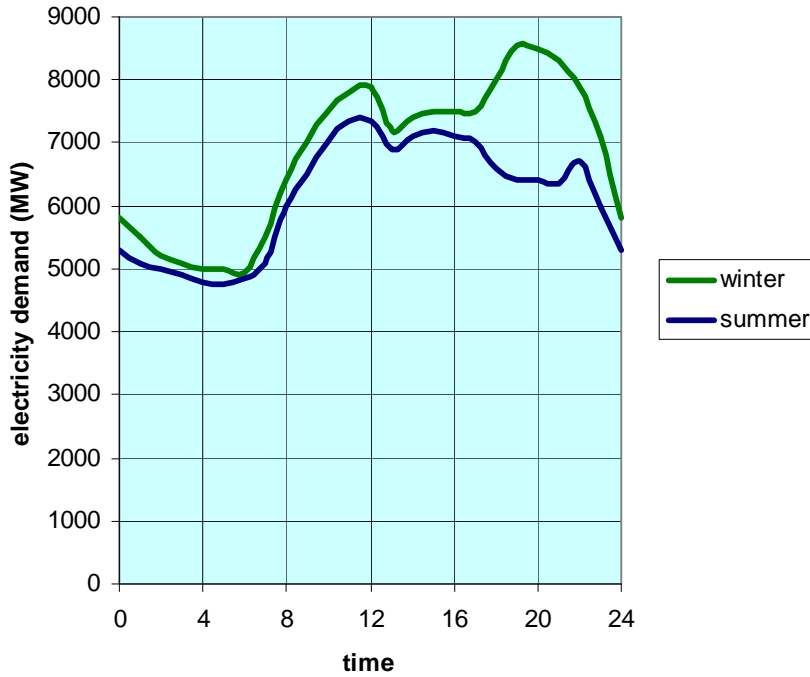


Figure 16: Typical electricity demand patterns in Portugal (2005).

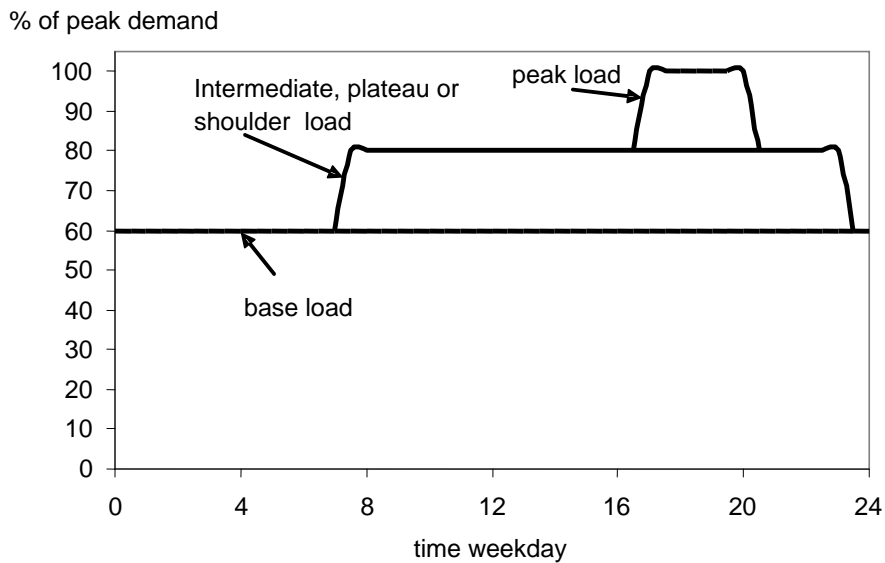


Figure 17: Base load, intermediate, plateau or shoulder load and peak load.

Electricity system operators talk about the load levels in terms of base load, intermediate, shoulder or plateau load and peak load. Figure 17 illustrates this. A first idea might be that all running generators might vary their capacity to meet demand. However, it would mean that they would run at part load most of the time, which is bad for fuel efficiency and for the specific maintenance costs and capital costs (see figure 8). Especially the more capital intensive power plants based on nuclear and coal should run close to their nominal load. More flexible plants, such as hydro power and the relatively cheap gas-fuelled engines and turbines, are more suitable to deliver fluctuating and peak load. The price of the fuel is less important

in that case. A part of the power plants has to run below the nominal power anyhow to be able to compensate for sudden failure (tripping) of one of the running plants. For such a contingency, an electricity supply system needs spinning reserve (synchronised and ready to deliver) as well as back up reserve (ready to synchronise).

4.2 Energy storage technologies

The problems arising from the dynamics in demand could be eased if cheap and efficient storage systems for electric energy existed. However, electric energy cannot be stored directly. [17], [18]. Mechanical and chemical means are needed for that. Examples are batteries, flywheels, pumped hydro and compressed air. Batteries have a limited capacity and require a high specific investment. A well known example is the lead-acid battery. A 12 volt battery itself requires about 150 € investment for a capacity of 83 Ah. If fully charged, such a battery holds 1 kWh of energy. Part of this stored energy, about up to 75%, can be released in three hours without damaging the battery and that roughly covers the duration of the peak in demand. If the discharge will not be too deep, the battery might survive up to 1000 cycles, which is roughly three years. For a weighted capital charge rate of 8% and a lifespan of three years, the capital costs of this $75/100 \cdot 1000/3 = 250$ W battery system that delivers electricity during 782 hours a year, equal 31 €cents/kWh. Some additional investment of about 50 €/kW is required for the AC to DC and DC to AC converters and for some control and monitoring equipment. That adds approximately 1 €ct/kWh to the costs, and the maintenance and control costs are on the same level. The process of charging and discharging has an efficiency of about 75%, which will cost 1.5 €cts/kWh if we consider the charge current to originate from base load capacity with a price of 6 €cts/kWh. Consequently, the total costs of peaking power from the battery system will be close to $31 + 1 + 1.5 + 6 = 39.5$ €cts/kWh. Flywheels require roughly a factor 10 higher investment than batteries, but their lifespan is much longer.

Pumped hydro is already widely applied as a means for indirect electric energy storage in many countries. The total capacity of pumped hydro in the EU-25 is 30 GW on a total generating capacity of 700 GW (data 2004). The flexibility of standard hydro power with respect to load following can also be used to cover the peaks. The EU-25 has about 100 GW of hydro power capacity excluding pumped hydro. The point is that hydro power is restricted to countries with a suitable landscape such as Österreich, Portugal, Sverige and Suomi. The literature gives a specific investment between 3.5 and 5 €/kWh stored energy for pumped storage [18, 19]. However, the capital investment in a new hydro project is about 1000 €/kW, if we take the Three Gorges project in China as a modern reference. For a lifespan of 40 years, weighted capital costs of 8% and maintenance costs of 0.3 €cts/kWh, a utilisation of the peaking capacity of hydro during 1000 hours a year renders 8.8 €cts/kWh additional costs, next to the 6 €cts/kWh of input power and the 1.2 €cts/kWh of conversion loss. The total costs of peaking electricity from pumped hydro is then $8.8 + 6 + 1.2 = 16$ €cts/kWh.

Other possibilities are storage via compressed air as well as electricity into hydrogen conversion followed by hydrogen into electricity conversion in a fuel cell. The costs of peaking capacity with compressed air appear to be close to those of pumped hydro. The hydrogen route has a low energy efficiency of about 25% [20], while the investments are close to 4000 €/kW. The ultimate costs and the low energy efficiency of the hydrogen route are still prohibitive. Fuel cells cannot yet fulfil the promises of excellent conversion efficiencies. The molten-carbonate fuel cell was expected to be top of the class with over 65% electrical efficiency, but a recent demonstration project with a 250 kW unit in Germany [21] had only 47%. Moreover, the maximum combined heat-and-power efficiency was just 70% compared with over 85% of engine-driven installations.

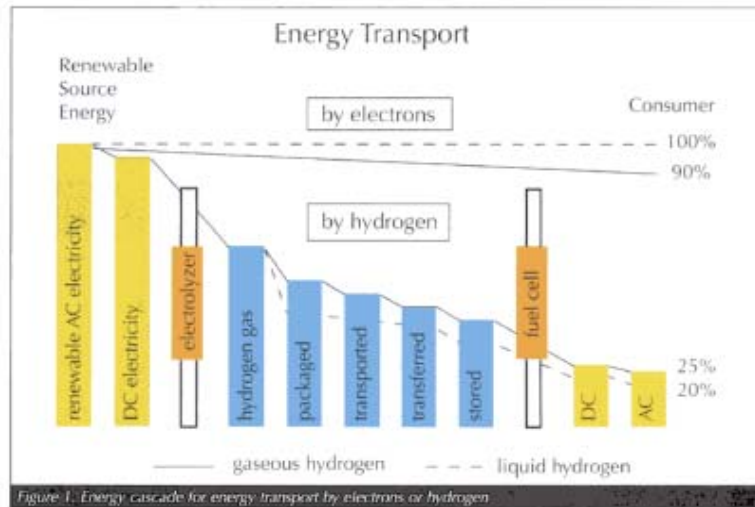


Figure 18: The poor efficiency of energy storage via hydrogen [20].

4.3 The dynamics of generating technologies

Electricity generators not only have to cope with the instantaneous variations in demand (regulating power), but also with sudden changes in total production power due to failure of individual generators. In a system where 10 generators of equal size carry the total load, failure of one unit will mean a load step of about 10% for the remaining units. The system operator in charge with system stability always has to make sure that sufficient spinning reserve is present to deal with failure of an individual generator. This is generally done by avoiding running all generators at full load. Directly after a trip of a generator, stand-by capacity has to be brought on line to ensure the availability of sufficient spinning capacity in case another unit trips. A stand-by unit should be ready for rapid synchronisation and ramping up of its contribution to the grid. System operators can offer financial compensation for regulating capacity, spinning reserves and back-up reserves, which are typical system services, or ancillary services. Generators can only make available such system services if they have suitable dynamic properties.

Table 3: Dynamic properties of different generators [3]

	Ramp rate	Start time to synchronisation
	% of rated power/minute	minute
Gas-fired steam	3	120
Coal fired steam	3	150
Aero derivative gas turbine	20	5
Gas turbine combined cycle	5	8
Diesel engine	100	0.5
Gas engine	30	0.5
Hydro	40	0.2

Steam-based power plants can not offer stand-by reserves that should be on line within 10 minutes. Moreover, such systems have a low ramp up rate that allows them to use only a limited amount of regulating capacity and spinning reserves. A typical compensation for spinning reserves is 0.6 €cts/kWh. The compensation should at least cover the O&M costs and additional fuel costs due to the running at a lower efficiency than at rated load, as well as the capital costs of the spinning reserve capacity. Stand-by reserves receive a compensation of around 0.4 €cts/kWh. This should at least cover the capital costs and the fixed O&M costs.

Frequency regulating capacity can render around 1 €cts/kWh. One should bear in mind that although the dimension of reserve capacity compensation has the unit kWh, these are virtual kWh resulting from having a certain capacity (kW) available during a certain time span (h). These prices can peak in case of temporary lack of reserve capacity. The recent past has shown regulation prices of up to 20 €cts/kWh during about 20 hours of extreme weather conditions. Spinning reserves sometimes rendered over 3 €cts/kWh [3]. Compensation for system reserves will be higher if the risk of high demand fluctuations and impact of generator failure is higher.

Equipment for spinning reserves and standby reserves should have low investment costs to optimise the revenues from delivering virtual power. Moreover, spinning reserve units should have a high part-load efficiency to avoid high specific fuel costs. Reciprocating-engine-driven generators are very suitable for such purposes since modern large-bore versions still have a net fuel efficiency of e.g. 41% at 60% load.

4.4 Supply reliability issues

The value of electricity is that high for many activities that interruptions in supply cause severe economic damage. Most interruptions are caused by faults and failures of transmission and distribution systems [22]. In The Netherlands, the country-wide average of 25 minutes outage per year is for 10% caused by high-voltage supply problems, 20% by low-voltage supply problems and 70% by medium-voltage problems [23]. Typical *faults* are damage caused by severe weather conditions and vandalism. *Failures* are related with equipment malfunctioning, human errors and overloading. Although large power plants themselves are quite reliable, the distance between generator and user is the bottleneck. Local generation, close to the user, is therefore of benefit. However, system planners erratically fear for a poor reliability of smaller units. Statistics can however prove that generation with multiple units gives a high combined reliability.

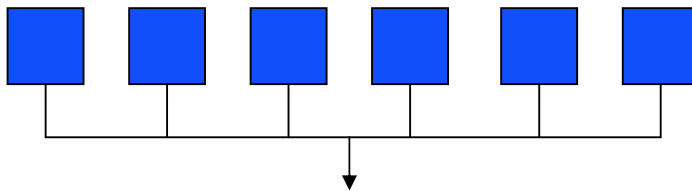
An availability of electricity of 99% results on average in 3.7 days of no electricity per year. In most European countries, the average supply reliability is slightly over 99.99%, i.e. less than 53 minutes per year no electricity. Such a high availability can never be reached with a single generator. A typical reliability of an individual modern generator system is roughly 99%. That applies for large-scale units as well as for units in the power range between 500 kW and 20 MW. Section 4.3 mentioned already that a single generator should never carry more than 10% of total electricity demand in order to avoid instability problems. Probability theory helps to determine the required number of generators with a given individual reliability to reach a desired combined reliability.

In the next example (see figure 19), only 6 identical generators will be used since otherwise too many permutations will blur insight. With 6 units in parallel with each a reliability R of 99%, the probability P that all units are running is $99/100 \cdot 99/100 \cdot 99/100 \cdot 99/100 \cdot 99/100 \cdot 99/100 = 94.148/100$ or 94.148%. This is the so-called product rule. The probability that one unit fails while the five remaining units stay running is $6 \cdot (1/100 \cdot 99/100 \cdot 99/100 \cdot 99/100 \cdot 99/100 \cdot 99/100) = 5.7059\%$. This is the so-called sum and product rule. It shows that there are six different possibilities that one unit fails ($R = 1/100$) while the other five stay running ($R = 99/100$). The risk that two units out of six fails is based on 15 different permutations resulting in $P = 15 \cdot (1/100)^2 \cdot (99/100)^4 = 0.001441$ or only 0.144%. Consequently, if the load is such that 5 units can carry the load of 6 units, the power availability approaches 99.85%. If 4 units can carry the load of the 6 in parallel, the power availability is close to 99.998%.

Mathematically, the probability P that exactly m units out of n with an individual reliability R will be running is:

$$P(m \text{ out of } n) = \frac{n!}{m!(n-m)!} R^m (1-R)^{n-m}.$$

With these methods, the number of spare spinning units needed to reach a combined reliability of 99.99% while each unit has a reliability of 99% can be calculated. The result is given in figure 20. In case one unit has the capacity to carry the full load, two extra units in parallel are theoretically required to reach the desired reliability. That means that 200% extra capacity has to be installed. In practice however, this will not work for steam-based power plants since such units can never make the 33.3 load step in case one unit fails. Only dedicated reciprocating engines are able to make such a load step. That is why preference is given to reciprocating engines in emergency and back-up installations of e.g. hospitals. With more than 100 generators in parallel, only 7% additional spinning capacity is needed to reach the desired combined reliability of 99.99%. The savings in investments compared with a small number of generators is apparent. Consequently, this results in another benefit of local generators which are relatively small by nature. Failure of a single unit that contributes less than 1% of total production requires only a small load step by the units remaining on line.



**P all units running: $99/100 * 99/100 * 99/100 * 99/100 * 99/100 * 99/100 = 94.148\%$
(product rule)**

**P one unit fails: $6 * (1/100 * 99/100 * 99/100 * 99/100 * 99/100 * 99/100) = 5.7059\%$
(sum and product rule)**

Figure 19: Probability example for 6 units in parallel.

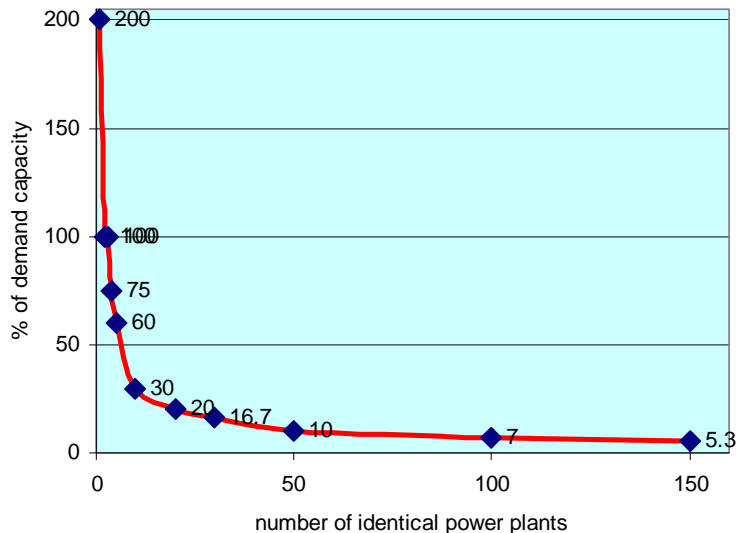


Figure 20: Relative amount of additional spinning capacity needed to reach a total generating reliability of 99.99% with identical power plants in parallel each having 99% reliability.

4. 5 Typical capacity issues of generators based on renewables

Renewable energy sources such as wind and photovoltaics have typical properties that distinguishes them from traditional electricity generators. Wind speed varies depending upon weather conditions, which in turn often depend on the season and even time of the day. Solar radiation is more predictable but only available during daytimes, again with a strong seasonal influence in some regions. Biomass production depends on the season and storage of biomass is not always easy since fermentation can easily occur in wet biomass.

4.5.1 Wind power characteristics

Air flows in a characteristic way from regions of high pressure to regions of low pressure. This applies for large-scale weather systems as well as for smaller areas. An example of a local phenomenon is that on a calm sunny summer day near the coast, the air above land heats up faster than above water this causing a sea wind to occur. During the night, the air above land cools off faster resulting in wind towards the sea. In general, wind speed has a stochastic character while the power derived from it is proportional with the third power of speed. No power is available below a certain wind speed while above a certain wind force, the generator has to be stopped and fixated in order to avoid damage. Figure 21 gives a typical probability distribution of wind speed and generated electricity.

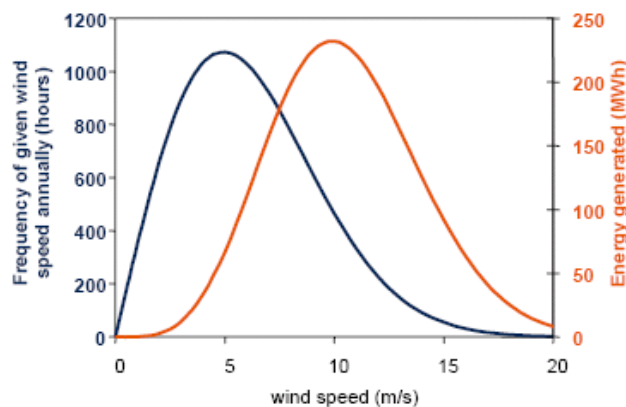


Figure 21: Typical wind speed and power distribution over the year.

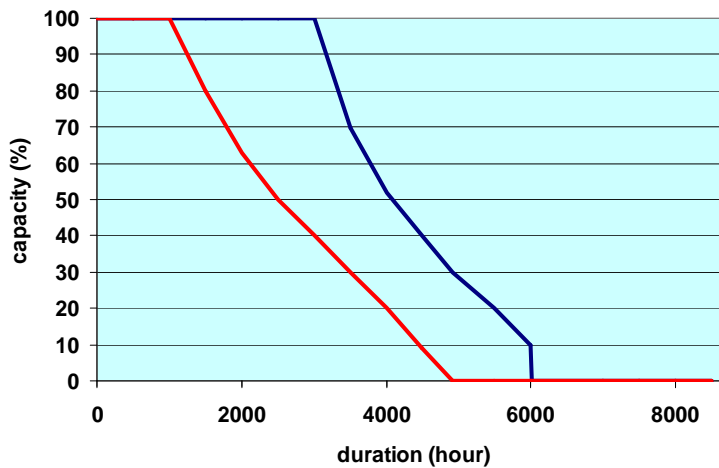


Figure 22: Production duration curve of an excellent and a standard wind site.

Figure 22 shows the production duration curve, or capacity utilisation curve, of an excellent site (blue) and a standard site (red). The maximum equivalent full-load utilisation is 24% for the standard site and 35% for the excellent site. For the standard site, the rated power of a windmill is only available during 14% of the time. In 2006, Shell and Nuon announced their common project for an off-shore wind farm of 108 MW in The Netherlands. It has a utilisation factor of only 30% and is therefore expected to produce 330 GWh/year for a specific capital investment of 2100 €/kWh. The unpredictability and stochastic nature of wind power means that the electricity produced has a low value on the open market since its capacity can never be guaranteed over a certain period. Wind power will therefore require additional investments in back-up capacity. Major grid stability problems can occur if a large wind park is running at full power and the wind speed exceeds the safety limit for the turbines. If wind is producing e.g. 20% of demand in such a case, the spinning reserve should be at least 20%. The revenues as guaranteed by the government (feed-in tariff and subsidies) are such that the project is economical, although the commercial production costs are over 11 €/kWh. References promoting wind power (and solar power) often give substantially lower production costs, but they generally use capital costs of only 5% of the investment which is not realistic in a competitive electricity business.

4.5.2 Photovoltaic power

The amount of insolation at a location depends on the latitude, the time of the day and the season. Figure 23 shows the typical daily solar irradiation in London, Madrid and Helsinki. The peak in midsummer might be welcome to compensate for the extra load from air conditioning in Spain but in London and Helsinki electricity demand clearly peaks in wintertime (see also figure 15). This means that extra back-up power and therefore extra investment is needed for solar power in cold and moderate climates. Solar power is also not suitable for system services such as frequency regulation, spinning reserves and back-up power.

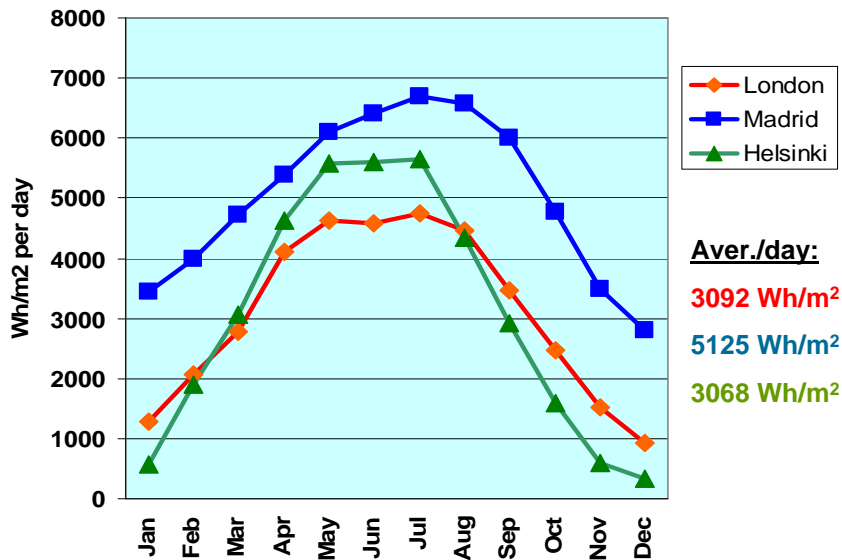


Figure 23: Daily solar irradiation at three different locations over a year.

Figure 24 shows that even at a prime location such as Madrid, the solar irradiation peaks at noon while it is almost negligible before 7 am and after 6 pm. That means that PV does not help to cover the weekday peak from 4 pm till 8 pm but only contributes to electricity

production during intermediate loads. This further increases the relative contribution of other generators to the demand peak. The average utilisation factor of PV in London and surroundings is just 10% while it is 23% in the Sahara. COSPP Magazine of March-April 2007 mentions a new 25 kW PV system on top of a Tesco store in Northern Ireland with just 9% utilisation. For a specific investment of 5000 €/kW, a utilisation factor of 15% and an expected life of 20 years, this results in a commercial electricity production price of about 50 €/kWh results. Again, the value of such electricity is low because of the non-controllable character and the impossibility to use it for system services. Extra capacity has to be installed because of that.

Compared to typical electricity production costs by fossil-fuelled generators and hydro power plants, PV electricity from the current technology is very expensive and only beneficial for the PV sector. This is especially the case if one takes into account the amount of energy to produce the PV elements (4 to 8 years of recovery time). However, PV power has a large potential in principle and government stimulation of research should be on a high level as long as there are prospects for improving the technology. It is not wise to subsidise large-scale applications of the current technology, since it is only a burden on the economy.

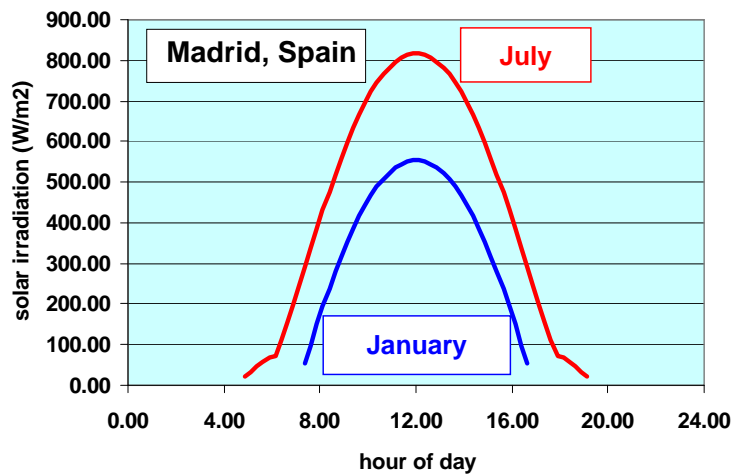


Figure 24: Solar irradiation over a day in Madrid during July and January.

5 Environmental aspects

Combustion of fuels causes emissions such as the greenhouse gas CO₂ and other components related with air quality such as NO_x and CO. In the EU-25, the electricity sector emits 3500 ton of SO₂ per year and 1900 ton of NO_x. There are cleaning methods available to reduce the directly polluting emissions to acceptable values in compliance with national and European legislation such as the UN-ECE (Gothenburg) and IPPC (Sevilla) rules. However, as long as CO₂ sequestration is not applied, fuel properties and conversion efficiencies determine the CO₂ emission in g/kWh. In 2004, the average CO₂ emission of the electricity sector was 400 g/kWh in the EU-25 rendering a total of about 1.2 Gton.

Table 4: Specific CO₂ production of fuels and specific emission for fossil-fuelled power plants.)*best practices, gross efficiency

Fuel type	specific CO ₂ production	fuel efficiency)*	specific CO ₂ emission
electricity			
	g/MJ	%	g/kWh
Methane	54.8		
Average natural gas	56	57.5	351
Black coal	98	46.0	767
Brown coal (lignite)	109	40.0	981

The specific CO₂ emissions in table 4 do not include the emissions caused by construction, erection and demolition of the power plants. The literature gives the following specific CO₂ emissions for different technologies if the full cradle to grave cycle is considered (table 5). It is not easy to investigate in the context of this project how reliable the figures given are, since advocates of certain technologies tend to give excessive values to competing technologies. Moreover, the numbers given are based on a utilisation factor that was not stated in the related literature. The last column in table 5 gives the numbers that serve as reference values in this report and in the Excel value model of this work package. The reference numbers should not be seen as the absolute truth but as a reasonable average value. Compared with the other fossil-fuelled options, there is clearly a substantial CO₂ benefit of gas-fuelled cogeneration.

Table 5: Total-cycle specific CO₂ emissions for state-of-the-art generating technologies [24] , [25].

technology	Minimum value	Maximum value	Reference this report
	g/kWh	g/kWh	g/kWh
Coal steam	815	1000	900
Gas steam	635	635	635
GTCC	356	472	400
Gas cogen	220	275	250
nuclear	6	26	15
Solar PV	50	300	200
Hydro	3	18	10
Wind	5.5	37	25

Water use for cooling purposes is an often overlooked issue. However, hot summers in Europe have already resulted in red alert for the electricity sector because of environmentally unacceptable overheating of cooling water in rivers, lakes and even coastal areas of the sea. Central generation has a typical water use as given in table 6. Local generation normally does not need water resources for cooling. Local power plants powered by reciprocating engines will normally use radiator cooling in case the heat released cannot be used. This is another benefit of local generation.

Table 6: Typical water use of central power plants [26]

<u>Plant type</u>	<u>specific water consumption</u>
	litres/kWh
Coal/steam	2.3
Nuclear/steam	1.9
Gas turbine combined cycle	0.95

6. Energy savings from cogeneration

Cogeneration, or combined heat and power (CHP), means using the heat that is available as a rest product from electricity production. Figure 25 illustrates the benefit of cogeneration for fuel efficiency. For the production of 1 kWh of electricity with the indicated 44% efficiency, 8.2 MJ of fuel is needed. This is already 1.8 MJ/kWh less than with today's 34.6% net efficiency of the EU-25 electricity sector. Moreover, another 3.7 MJ is saved because the heat released finds a useful application.

Central electricity producers argue that a large gas-turbine combined cycle might have a fuel efficiency of 57.5%. However, since such units are generally located at longer distances from the end user, the transmission and distribution losses can amount up to 8% points, resulting in a net fuel efficiency of 50%. Compared with the GTCC, good cogeneration as in the example of figure 8 still saves $3.6 / 0.50 + 3.7 - 8.2 = 2.7$ MJ/kWh. That is a saving of 37.5% of the fuel input to the GTCC. If 40% of a nation's primary energy use goes to electricity production, $37.5 \cdot 0.40 = 15\%$ of TPES will be saved if all electricity is produced by good cogeneration instead of by large-scale GTCC and separate boilers. In Denmark and The Netherlands, cogeneration produces more than 40% of all electricity. The savings in primary energy is the reason that the European Commission promotes the use of cogeneration (see the EU cogeneration Directive).

The following mathematical expression rapidly gives the percentage of primary energy savings with cogeneration $S\%$:

$$S\% = \left(1 - \frac{1}{\eta_{\text{Ecogen}}/\eta_{\text{Ecentral}} + \eta_{\text{Qcogen}}/\eta_{\text{Qseparate}}}\right) \cdot 100\% \quad (3)$$

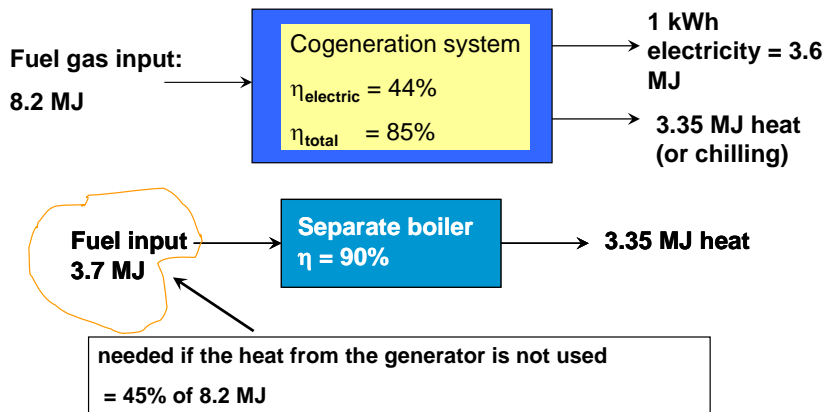


Figure 25: Example of the fuel savings by cogeneration.

The specific CO_2 emissions of a natural-gas-fuelled cogeneration unit are relatively low. With a 44% net fuel efficiency, just 458 g of CO_2 is produced per kWh of electricity. Moreover, with the 85% combined cogeneration efficiency, the production of 207 g of CO_2 from the 3.7 MW for heating is avoided for every kWh of electricity, resulting in a net specific CO_2 emission of only 250 g/kWh. Another way of expressing the specific CO_2 emissions is by dividing the CO_2 produced by the combustion process by the sum of the electricity and heat produced expressed in kWh. That renders a specific CO_2 emission of 237 g/kWh. The resulting CO_2 emission from a gas-fuelled CHP plant is roughly the same as that for a lignite fuelled power plant of which 75% of the produced CO_2 has been removed from the exhaust gas and sequestered.

7. Summary of possible value aspects of local electricity generation.

The previous chapters have shown that many aspects influence net fuel efficiency, emissions, supply reliability and end price of electricity. Fuel savings and costs reductions can be beneficial for some stake holders while for others it will mean loss of business. Using a relatively clean fuel such as natural gas might result in high fuel efficiency and low emissions but at the same time reduce security of supply since the fuel stems from a country using energy exports as a political instrument. Governments with frequently changing and therefore unreliable support and taxation methods might hamper investments in better energy systems. Many governments receive higher revenues with higher energy sales thanks to energy levies and VAT. Every discussion about the value of local electricity generation has to include the effects on each stake holder. It is not possible to speak of an absolute combined value in general.

It is possible to discuss values in the context of:

1. Costs for the end user,
2. Security of supply,
3. Carbon emission reduction,
4. Supply reliability,
5. Import and export balance,
6. Government budget,
7. Producer business profits.

This chapter will give some details and show general trends of the seven aspects mentioned. Chapter 8 will show more detailed information on five selected EU-15 countries.

7.1. Initial comments on the values of local generation

Figure 26 shows the basic generating costs per net kWh delivered to the end user as a function of the utilisation factor. A net efficiency of 40% has been used for nuclear and coal, 50% for the CCGT and 42.5% for the gas-engine cogeneration system with a combined CHP efficiency of 85%. The price of the gaseous fuel for the cogeneration installation has been presumed to be the same for a heating boiler. Apart from the presumed CO₂ costs of 15\$/ton, no taxes have been taken into account. Wind and solar are not given in this diagram because of the uncontrollability of their utilisation factor. Wind electricity with a typical utilisation factor of 25% would cost 10 €/kWh and PV electricity 50 €/kWh. Cogeneration is the best option under all circumstances. However, in most European applications, cogeneration will only run for 60% of the time because of a reduced heat demand in summer, except in industrial applications. After cogeneration, the nuclear option is the cheapest for normal base load; for intermediate load with 60% utilisation, all three centralised options are about equal. The GTCC and gas-engine cogen are clearly the cheapest for a low utilisation factor. However, such a low utilisation factor typically originates from peak demand and a steam cycle is less suitable for that. In practice, all steam-based generators used for peaking power will have higher costs than those indicated in figure 26 because of a long initiation time. In the USA, reciprocating-engine driven peaking plants are increasingly popular because of their high efficiency, fast starting, high ramping-up rate and low specific investments. The size of such plants varies between 75 and 200 MW, with up to 20 modular individual generating units in parallel. One should bear in mind that central generation can also serve to provide heat for e.g. district heating, albeit with a lower combined efficiency than that of a local generator that has to cover just a short distance to transport the heat. District heating systems in Polska are said to lose 50% of their input heat due to losses.

The generation costs in figure 26 contain already a 15% profit on own capital invested (= typically 30% of the total capital) for the generating company. However, the transmission and distribution costs were not yet included. If we put the transmission costs at 0.6 €/kWh and add 0.4 cts for distribution costs for industrial users to the generating costs, we find the

average price level of electricity in the EU-25 for industrial users. Industries and commercial users can clearly benefit from cogeneration; Process plants often need much steam. In that case, a combination of a gas turbine with a heat-recovery steam generator (HRSG) is the best option. Cogeneration can lower their electricity costs by 2 to 3 €cts/kWh (30 to 50% reduction) if the benefit of the heat used is subtracted from the electricity production costs, provided the heat user can buy the gas for the same price as the power plant. Such a costs reduction substantially increases the economic leverage of energy use. The central electricity production sector will lose business in this case but the gas supplier will sell more.

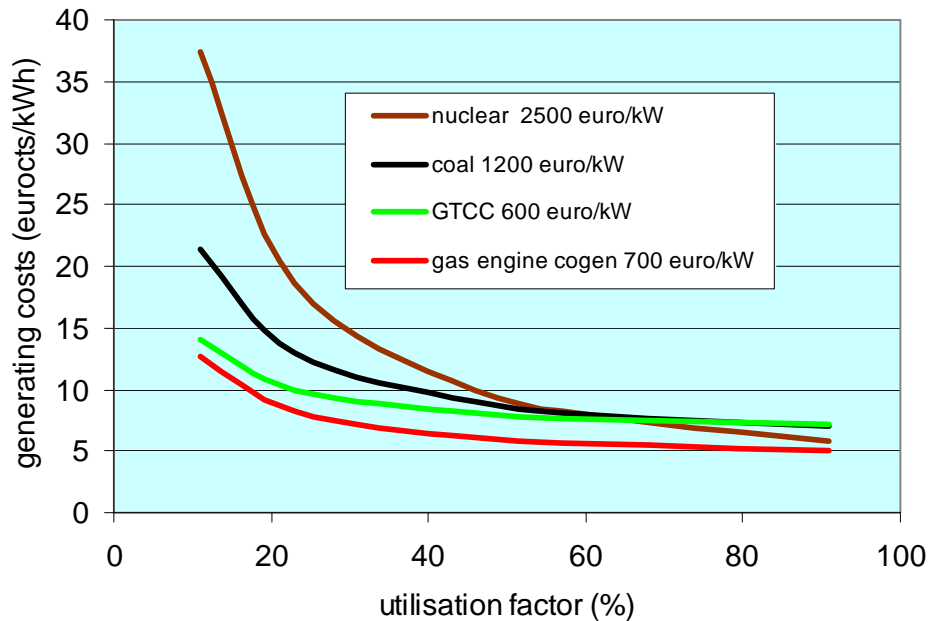


Figure 26: Basic generating costs per net kWh delivered to the end user. O&M from table 2; 15 €/ton CO₂; 30 years plant life; 8% discount rate.

The specific CO₂ emissions of the different options in figure 26 are 888 g/kWh for the coal-fired power plant, 468 g/kWh for the GTCC, 250 g/kWh for the local cogen plant and only 15 g/kWh for the nuclear plant. Although the coal fired plant has to pay 1.3 €cts/kWh for the CO₂ emissions in this case, that does not change its specific emission level. If that money is given to the nuclear power plant because of its low emissions of greenhouse gases, it would make the nuclear option even more attractive. However, if the external costs of nuclear waste and its socio-political costs would be taken into account, the cogeneration option still remains the winner. A poll carried out in February 2007 revealed that 61% of Europeans are against nuclear energy while 30% support it.

The previous sections show that natural gas is a very attractive fuel for electricity generation, for peaking purposes, base load as well as for cogeneration. However, the EU will soon depend largely on gas from Russia and the Middle East, while countries such as China and the USA are also eager to get that gas. From a security of supply point of view, governments want to diversify in fuel types. Coal is still abundantly available in many regions in the world and the risk is very small that it will be used as a political instrument.

If a country has a national industry for a certain generating technology, that industry creates jobs and revenues from exports. The same can apply for an indigenous fuel such as coal. Importing all equipment, spare parts and fuels is a burden on the economy. This is especially the case in countries such as Suomi and Poland where specific energy consumption by industry is high. Governments receive money from electricity use via energy levies and VAT,

primarily from end users such as households that cannot claim back the VAT (see figure 10). They also charge natural gas consumption with an energy levy, like in The Netherlands. There, every gas customer has to pay energy tax on gas according to table 7. In addition to that, end customers pay 19% VAT. The base price for gas is already much higher for private customers than for large-scale users because of high standing charge and distribution charge.

Table 7: Example of energy tax on natural gas in The Netherlands

Annual quantity used	energy tax
	€cts/m ³
< 5000 m ³	14.94
5000 – 170,000 m ³	10.19
170,000 m ³ – 1 Mm ³	3.11
1 M – 10 Mm ³	1.15
> 10 Mm ³	0.76

Reliability issues are difficult to discuss in general, since much depends on the local situation in each member country. A reliable electricity supply is a crucial factor for an industry or service company to decide about a new location. The Netherlands has the most reliable electricity supply in the EU-25 and hosts much local generation. However, the population density and economic activity density are also the highest in the EU-25 which reduces the length of the electricity distribution chain.

8. Detailed 5-country analysis

Annex 1 of the project plan for ELEP states that work package 3 should only perform a detailed study of the value of local electricity generation for 5 representative EU-15 countries. During the ELEP kick-off meeting, the consortium decided to choose Denmark, Deutschland, Italia, Polska and Portugal as the representative countries. However, to increase insight in the economic impact of local generation and to increase statistical reliability, the WP3 owner decided to use the EU-25 in total for determining the relationship between economy and electricity production and consumption. The results are given in chapter 2. On hindsight, based on chapter 2, it would have been better to take Suomi instead of Danmark as a Nordic country since specific electricity use in Suomi differs substantially from that in Danmark and Deutschland.

In the beginning of the project, the WP3 owner composed a questionnaire to be completed by the other WP3 partners. This questionnaire was agreed upon during a project meeting but later it appeared that most of the partners had real difficulty to provide data otherwise than those easily available in the public domain. Comparison of data in the partly completed questionnaires with data from Eurelectric, Eurostat and the IEA revealed many inconsistencies. As a result, the WP3 owner decided to use primarily alternative means to access the required data. This has considerably delayed the project.

8.1 General aspects

The TPES per capita (GJ/cap) does not differ much in the five countries selected (see table 8). However, the Energy Intensity of the economy shows large variation. In Polska, almost a factor 5 more energy is needed for the same amount of Euros (2004 value) in GDP as in Danmark. It is true that the general purchase power parity (PPP) of a Euro is a factor 2.4 higher in Polska than in Danmark, but fuels and electricity should be considered as EU commodities in this report. The electricity supply per capita shows the same tendencies as TPES. The electricity use per € of GDP is lower in the richer countries than in the poorer countries. System use and distribution loss cause the difference between gross and net electricity supply/capita.

Table 8: Key energy related economic data of the 5 selected EU countries (year 2004) [1].

Property	Unit	Danmark	Deutschland	Italia	Polska	Portugal
Gross Domestic Product/capita	k€/cap	40.1	34.6	22.0	5.3	13.6
Total Primary Energy Supply/cap	GJ/cap	155	176	134	101	104
Energy intensity TPES/GDP	MJ/€	3.87	5.09	6.09	19.06	7.64
Gross Electricity Supply/capita	MWh/cap	6.97	7.24	5.90	3.75	4.91
Gross Electricity Supply/GDP	kWh/€	0.174	0.209	0.268	0.708	0.360
Net Electricity Supply/capita	MWh/cap	6.10	6.23	5.09	2.61	4.28
Net Electricity Supply/GDP	kWh/€	0.152	0.179	0.231	0.492	0.314

Danmark has the highest GDP/capita (40.1 k€/capita) of the 5 countries selected. The energy intensity of its economy is 3.87 MJ/€, which is just 60% of that of the EU-25. The net electricity intensity of the economy is 0.152 kWh/€, which is about 64% of that in the EU-25. In that respect, the Danish economy is rather energy efficient. The Danish economy is largely based on services and transport. Private final consumption expenditure (PFCE) is 47% of GDP, which means that the public sector is large.

Deutschland has a 15% lower GDP/cap than Danmark, but its PFCE is 56% of GDP since its public sector is relatively smaller. The German economy has still a strong manufacturing sector, which tends to increase the energy and electricity intensity of the economy compared with a more services-based economy. The energy intensity equals 79% of the EU-25 average while the net electricity intensity is 75% of the EU-25 average.

Italia's GDP/capita is with 22 k€ slightly below the average of 23.4 k€ in the EU-25. The main cause of this is the relatively poor south. The Italian PFCE equals 58% of GDP. Although the absolute energy and electricity use per person in Italia are just slightly lower than in Danmark, the intensity in MJ/€ and kWh/€ is substantially higher.

In Polska, the manufacturing and agricultural sectors still provide many jobs. The country clearly has to make a leap forward, since its GDP/capita is just 23% of the EU-25 average. Fortunately, the GDP expressed in PPP is a factor 2.5 higher but that is not sustainable on the long run, especially with European wide commodities such as fuels and electricity. The PFCE is close to 65% reflecting a low tax regime. Both the energy intensity and electricity intensity are unsustainably high compared with the EU-25 average. It means that Polska has a poor economic leverage of energy use.

Portugal has a strongly growing economy but that is needed to catch up with the rest of the EU-15. The energy intensity and electricity density of their economy are twice as high as those in Danmark, although its climate is much milder. Its PFCE is with 64% about the same as in Polska.

8.2 The current state of electricity production

The average efficiency of electricity production differs considerably from country to country (see figure 27). Italia has the highest net supply efficiency (38.4%) because of a high production efficiency (44.5%) and relatively low system use. Polska has the lowest efficiency (23.8%) because of a low production efficiency (34.2%) and high system use and distribution losses. No country even approaches the reference values for the supply efficiency of modern equipment as used for composing figure 26 (coal and nuclear 40%, CCGT 50%). It is important to notice this when discussing reference values in comparing local and central generation.

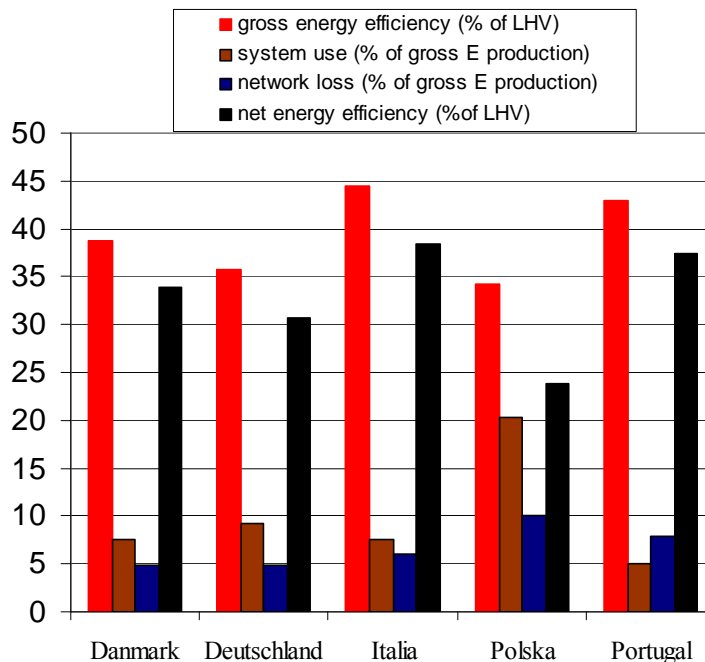


Figure 27: Gross production and net supply energy efficiency of electricity production in the 5 selected countries with system use and network loss (2004).

The observed low efficiencies arise from the fuel mix, old equipment and part-load running because of frequency control, spinning reserves and peaking with less suitable equipment. Table 9 gives the fuel mix and table 10 gives the utilisation factor. Figure 28 shows the part of

hydro electricity, imports and exports in total supply. Hydro, imports and exports can serve as a means to cover peaks and contingency reserves.

In Polska, 92% of all electricity is produced by coal and lignite in power plants of a considerable age. These plants have to cover the dynamics in demand, which means they have to run much time on part load or on/off operation. The relatively low utilisation factor of the power plants corroborates this. Imports and exports are not large enough to act as a buffer to keep the generators running at their rated load most of the time. Indigenous solid fuels will probably remain very important for Poland, but the addition of gas-fuelled equipment for peaking purposes and replacement of old power plants by modern ones could increase the average production efficiency to 44%. That is a reduction of about 30% in specific fuel consumption for electricity production. Power plant replacement together with grid renewal and reduction of the system loss could render a net supply efficiency of 40%, which is considerably better than the current 23.8%.

Table 9: Electricity generated by fuel source (2004) [1]

Primary source	unit	DK	D	I	PL	P
Nuclear	%	-	27.5	-	-	-
Hard coal	%	46.1	22.3	15.0	55.5	32.9
Lignite	%	-	26.0	-	36.4	-
Natural gas	%	24.7	10.1	42.8	2.0	25.9
Oil	%	4	1.7	19.4	1.6	12.6
Hydro	%	-	4.6	16.5	2.4	22.5
Wind	%	16.3	4.2	0.6	-	1.8
Biomass	%	8.8	1.9	1.8	-	4.0
Other	%	0.1	1.7	3.9	2.1	0.3
Total	%	100	100	100	100	100

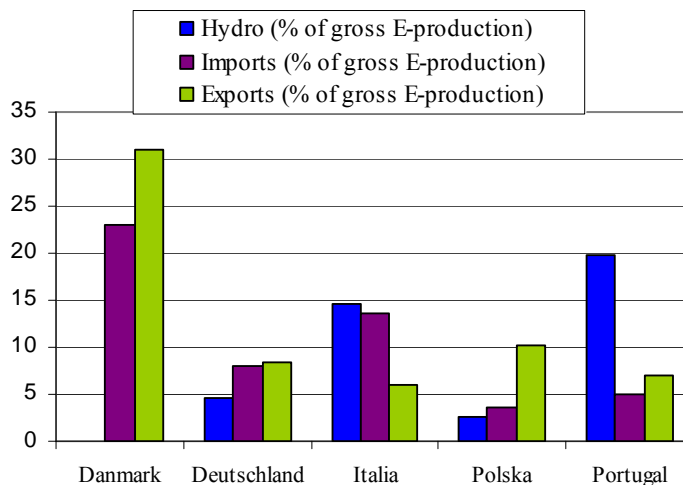


Figure 28: The relative amount of hydro, imports and exports (2004) [1]

In Denmark, many steam-based power plants can run on coal as well as on natural gas. Moreover, they are often integrated into a district heating system. If such cogeneration systems cover a large part of heat demand in a country, a relatively low electrical efficiency is not always negative with respect to total fuel efficiency if the heat used is taken into account. Denmark has a high amount of wind power. The installed wind capacity is 23% of the total

installed electricity production capacity. Still, that wind produces 16% of all electricity in Denmark notwithstanding the low utilisation factor of 24%. It means that Denmark has much

Table 10: Utilisation factor per fuel type (2004) [1]

Energy source	unit	DK	D	I	PL	P
Nuclear	%	-	92.7	-	-	-
Hard coal	%	?	50.6	57.1	62.6	95.5
Lignite/peat	%	-	81.9	-	68.6	-
Natural gas	%	38	36.0	47.8	44.9	96.5
Oil	%	-	22.7	39.5	-	52.5
Hydro	%	-	38.6	27.5	18.5	23.9
Wind	%	24	17.3	18.7	-	16.8
All	%	34.6	55.9	42.6	55.4	40.5

back-up capacity for the time that wind power is not active. The total utilisation factor of generating equipment in Denmark is therefore only 34.6%. Consequently, the capital costs of electricity are rather high in Denmark. This is reflected in the domestic and industrial electricity costs (compare figures 10 and 12) which rank among the highest in the EU-25. Moreover, much spinning reserve, back-up reserve and frequency control capacity is required, especially in case of wind speeds approaching the safety shut-off limit. If the wind capacity runs at full power, it more than covers minimum electricity demand in Denmark. At the same time, cogeneration units might have to run to produce heat during a cold night. Denmark extensively uses imports and exports to solve the problems associated with temporarily excess and lack of power. One might state that it puts the technical burden of balancing on other countries. The economic value of commodities in times of overproduction is very low, so exporting electricity outside peaking and intermediate hours does not yield substantial revenues. More temporary heat storage and less unlimited feed-in by wind power might help to reduce the problem of too much wind capacity. Anyhow, Denmark is an interesting example of wind power pushing up the costs of electricity.

Deutschland produces a substantial amount (27.5%) of its electricity with nuclear power plants and lignite-fuelled plants (26%). The plants have an utilisation factor of viz. 92.7% and 81.9% meaning that they produce all base-load electricity. Consequently, the coal-fired plants have to carry the intermediate load while natural gas and hydro cover the peak load. Wind power in Deutschland has a capacity factor of only 17.3% notwithstanding the fact that it has preferred feed-in access. This reflects again the poor dispatchability of wind power. Ultimately, Deutschland reaches a net supply efficiency of only 31%. Electricity prices are relatively high in Germany

Italia has much generating capacity compared with its demand. As a result, the combined utilisation factor is low. Oil-fuelled capacity serves for peaking in combination with hydro and imports. Italia appears to rely on other countries for much of its dynamics in demand. The majority of the gas-fired equipment is GTCC, which explains the relative high electricity production efficiency. More local production of electricity can increase the net supply efficiency since that will reduce the distribution losses. The strange thing is that Italia charges high energy levies on domestic as well as industrial users while the amount of capacity based on renewables is small. Apparently, not much of the levy revenues is fed back into system improvement in Italy.

In Portugal, coal-based and gas-based power plants run almost around the clock to produce base load. The gas plants are primarily GTCCs. Reciprocating engines fuelled by oil and hydro power provide intermediate and peaking power. Because of its typical climate, the peaks in demand are not so pronounced in Portugal. Portugal is planning to introduce much

wind power and that can be integrated with back up from hydro including pumped storage. More local generation can decrease the relatively high distribution losses in Portugal.

8.3 The impact of cogeneration on fuel use and electricity costs

Chapter 6 has already explained the possible fuel savings benefits of cogeneration. The example given there concerns high-efficiency cogeneration. Section 7.1 illustrated financial benefits of cogeneration. Each of the 5 countries under investigation has already cogeneration, albeit to a different extent. The skill is in finding sufficient suitable heat usage that coincides with electricity demand. Table 11 gives a relative share in total electricity production from [27, 28]

Table 11: The share of CHP in electricity production (2004)

Country	Danmark	Deutschland	Italia	Polska	Portugal
Cogen share	50%	9.3	8.1	17	11

Table 12 gives total heat demand in the 5 countries and the contribution of heat produced by cogeneration. It appears that just a small part of heat demand is covered by cogeneration. Especially domestic heat demand has much space for additional cogeneration. Domestic micro cogeneration offers an interesting solution here, since the pattern in domestic heat demand shows a high correlation with the pattern in domestic electricity demand. Micro cogeneration can therefore serve as a good peak shaver. In Deutschland and Polska, cogeneration in industry is underdeveloped. The main reason is the existing central capacity based on coal and lignite in these countries. These central units are relatively old and have been written off in the days of vertically integrated electricity companies. The specific capital costs of electricity from these power stations are relatively low. In Denmark, it will be difficult to install substantially more cogeneration, notwithstanding the low coverage of heat demand. The reason is the already mentioned large amount of uncontrollable wind power that can lead to switching off generators while still heat is needed. In such cases, it might be practical to use electrical heating. Portugal exploits its cogeneration potential already quite good.

Table 12: Heat demand per sector and the contribution of cogeneration

Heat demand	unit	Danmark	Deutschland	Italia	Polska	Portugal
Industry	TJ	177	2082	?	1905	242
Services	TJ	1523		?	4586	9
Households	TJ	752	13713	?	675	7
Total	TJ	2452	15795	?	7166	258
Cogeneration	TJ	122	534	190	280	56
Cogeneration	%	5.0	3.4	?	3.9	21.7

In order to discover to what extent modernisation of existing CHP installations could improve efficiency, it is necessary to know the current efficiency. However, there appears to be not a good overview of performance data of CHP installations in Europe. The combined heat and power efficiency as derived from the literature [27] is very low in Italia and Polska (see table 13). Even in Denmark, the combined efficiency is somewhat disappointing. One cannot state that this is quality cogeneration. The problem with these data is that it includes power plants of which just little heat is used as well as heating plants that produce only a small amount of electricity. The data in table 13 are not helpful in determining the real performance of dedicated CHP installations but nothing else was available.

Table 13: Cogeneration performance in % of the lower heating value according to [27]

	Danmark	Deutschland	Italia	Polska	Portugal
Electrical efficiency	21.8	21.7	10.0	6.7	17.8
Heat efficiency	36.7	56.7	21.4	19.9	56
Combined efficiency	58.5	78.4	31.4	26.6	73.8

8.4 Fuel costs for the nation because of electricity production

In this section, we presume fuel prices as indicated in figure 9. Table 14 shows the fuel costs that have been calculated by using the fuel consumption for electricity generation per country as found in [1]. The column with 'fuel costs/imports' is a virtual one that gives the fuel costs expressed as a percentage of all imports in case all fuel was imported. Table 14 serves to visualise the burden of fuel use for electricity generation on the economy. Even if the installation of more local generation could save 25% of fuel for electricity generation, only Polska will see a substantial benefit. For the other four countries, the difference in burden on the economy is very low. This is probably the reason that national governments pay little attention to energy savings. One should bear in mind that Polska consumes 84% of its hard coal production while 54% of inland consumption is used in power plants. Lignite and peat complete the bulk of the rest of the fuels for its power plants. The Polish coal mines went through difficult times during the last decade because of low coal prices due to overproduction on the world market. Close to 200,000 jobs were cut so that currently just slightly more than 100,000 miners are active. The Polish government has paid much money for mine restructuring. The annual hard coal production in Polska of about 100 million ton (22 GJ/ton), at a reference export price level of 3.5 €/GJ, would render an annual sales sum of 7.7 billion € or 77 k€/miner which seems reasonable. Improving energy efficiency in Polska might mean more job cuts in mining. However, the world market for coal is growing again.

Table 14: Fuel costs for electricity generation as a percentage of GDP and percentage of the total import value.

country	Fuel costs/GDP (%)	Fuel costs/imports (%)
Danmark	0.7	1.9
Deutschland	0.5	2.0
Italia	1.0	5.3
Polska	2.7	9.1
Portugal	1.1	3.2

Danmark produced almost half of its electricity needs from imported hard coal in 2004. Wind and biomass contributed to 25% and the rest came primarily from domestic natural gas. In Deutschland, nuclear power, indigenous hard coal and lignite/peat each contribute to about 25% of electricity production. The bulk of the rest originates from natural gas, biomass and wind. It means that also in Deutschland jobs are at stake if the efficiency of the electricity sector improves without possibilities to turn to fuel exports. Lignite and peat are less suitable anyhow for long-distance transportation. Italia's electricity production is for 40% derived from natural gas, 20% from petroleum products, 15% from coal and 16% from hydro. The bulk of the fuels is imported, so the Italian economy will benefit directly from a better efficiency. Portugal relies for 20 to 25% on hydro power, while the rest comes from imported coal, gas and petroleum products. Also Portugal would benefit from an improved efficiency of the electricity sector.

This section 8.4 shows that with the current fuel-price levels, the burden of fuel prices for electricity generation expressed as a percentage of GDP or of total imports is not very high, apart from Polska and may be Italia.

8.5 Electricity costs for the end user

An industrial, commercial or domestic end user will benefit from a lower electricity price. For an industrial user with an average revenue of 2 €/kWh (see chapter 2) and specific electricity costs of 6 €/kWh, a 10% reduction in electricity price will increase the financial leverage by electricity use from 33.3 to 36.7. However, for electricity intensive industries such as aluminium and copper smelters, 10% reduction in electricity costs will make a substantial difference in an absolute sense. This applies also for the energy intensive industry in Polska. Other countries in the EU-25 that will typically benefit from lower electricity prices for industry can be found in Figure 4. Examples are Ceska, Eesti, Luxembourg, Suomi and Sverige.

Notwithstanding common belief, domestic electricity use put just a small burden on the household budget. If we presume the household budget per capita to be the GDP/capita times the private final consumption expenditure percentage, we can calculate the relative costs of domestic electricity use. The results are given in table 15. On the average, citizens spend only about 2% of their net income on electricity. Relatively, electricity is expensive in Danmark and cheap in Deutschland. A 10% cost reduction in electricity prices will not noticeably improve the household budget. If one takes into account the value of domestic electricity use with respect to extension of the day (light), comfort and entertainment, electricity is very cheap. However, doubling of the domestic electricity price due to e.g. much investment in renewables will have take another 2% from the household budgets.

Table 15: Burden of the annual electricity costs on the household budget/capita (electricity price for 2006, other data for 2004).

country	dom el.use	el.price	el.costs	GDP/cap	PFCE	net income	burden
	kWh/cap	€/kWh	€	€	%	€/cap	%
Danmark	1914	24.56	470	40176	47	18882	2.5
Deutschland	1700	18.73	318	34619	56	19387	1.6
Italia	1150	21.08	242	22028	58	12776	1.9
Polska	597	11.37	68	5298	65	3443	2.0
Portugal	1189	13.74	163	13609	64	8710	1.9

8.6 Value aspects for electricity producers.

In a fully liberated and competitive market, electricity producers try to maximise their profit with minimum risks. Anti-trust authorities and regulators try to ensure that real competition exists. In a real open European energy and electricity market, with sufficient cross-border transmission capacity, no national policies should influence the power plant business. The reality is different. In Polska and Deutschland, artificially cheap indigenous fuels dominate the market. The most important disturbing factor in the production arena is the use of power stations that have already been fully paid for under the former vertically integrated regime. Producers that own such old coal-fired stations can always beat gas-fired stations and newly built stations with lower prices since they hardly have any capital costs. That is the basic reason that investors are still hesitant in building new capacity and replace fuel-inefficient installations. In Poland, a written-off power plant running on hard coal of 2 €/GJ and having a net efficiency of 24% and no CO₂ charges can produce electricity for 4 €/kWh and that explains the low electricity price there. A new coal-fired power plant with a net supply efficiency of 40% would add 2 €/kWh of capital costs, reduce the specific fuel costs by 1 €/kWh and ultimately have about 6 €/kWh production costs. A CO₂ charge of 15 €/ton would add 2 €/kWh to the costs for the old plant and 1.3 €/kWh for the new plant. Even then, the old plant is on the short term more economical than the new one. Fully depreciated (written-off) power plants are the largest barrier for innovation of the EU electricity production capacity. At some moment in time however, they have to be replaced.

A general and fair comparison between the different methods of electricity production and supply is only possible for new cases. The costs of some different options are given in tables 16 and 17, with all the relevant boundary conditions so that the reader can judge the underlying presumptions. As has been explained before, the figures for wind power are just indicative, since the non dispatchable character of wind power requires additional back-up power. Steam-based central power plants might also be used to some extent for cogeneration purposes, but that is not practical in many cases. That's why the cogeneration option for such plants has not been presumed in tables 16 and 17. The reader can however easily add that option.

Table 16 confirms that for base load, cogeneration is the most energy efficient and cost effective solution, even with a relatively high fuel price. This is caused by the relatively low investments costs and the high fuel efficiency. The specific CO₂ emission of 249 g/kWh for local cogeneration is also the lowest of all the fossil-fuelled options. If 70% of the CO₂ emission from a modern coal-fired plant would be sequestered, the plant would have the same specific CO₂ emissions as a natural-gas-fuelled cogeneration plant. Consequently, natural-gas-fuelled cogeneration is not only of benefit for the economics of the generator, but also for low CO₂ emissions and optimum fuel utilisation.

Table 16: Costs analysis of different electricity production concepts (base load with 85% utilisation, except for wind).

Power plant type		nuclear	coal	GT CC	Wind offshore	Local cogen
Specific investment	€/kW	2500	1200	600	2100	700
Own capital	%	30	30	30	30	30
Profit rate	%	15	15	15	15	15
Bank interest level	%	5	5	5	5	5
Discount rate	%	8	8	8	8	8
System life	years	30	30	30	20	30
Utilisation factor	%	85	85	85	30	85
Construction time	months	60	45	36	6	4
Fixed charge rate	%	8.9	8.9	8.9	10.2	8.9
Specific capital costs	€cts/kWh	3.64	1.67	0.81	8.35	0.84
Fuel price	€/GJ	1	3.5	7	-	7
Gross fuel efficiency	%	46	46	57.5	-	44.5
System use	%	6	7	4	2	2
Net production efficiency	%	43.2	42.8	55.2	-	43.6
Specific fuel costs	€cts/kWh	0.64	2.27	3.52	-	4.46
Insurance premium	% investm.	1	1	1	2	1
Fixed annual costs	% investm.	0.9	1.3	1.7	0.8	2.1
Spec. maintenance	€cts/kWh	0.6	0.5	0.5	0.4	0.5
Total additional costs	€cts/kWh	1.25	0.87	0.72	2.62	0.78
CO ₂ price	€/ton	15	15	15	15	15
Specific CO₂ emissions	g/kWh	45	824	365	25	462
Specific CO₂ costs	€cts/kWh	0.06	1.24	0.55	0.04	0.69
Product costs (no cogen)	€cts/kWh	5.59	6.05	5.60	11.01	6.77
Cogeneration efficiency	%					85
Cogen benefit CO ₂	g/kWh	-	-	-	-	213
Net CO₂ costs	€cts/kWh	-	-	-	-	0.37
Cogen heat revenue	€cts/kWh					2.55
Total costs		5.59	6.05	5.60	11.01	3.90
Specific CO₂ cogen	g/kWh	-	-	-	-	249

Although producing only peaking power naturally results in higher specific capital costs than for base load, it is needed to keep the electricity system stable. To calculate the electricity production costs, the boundary conditions of table 16 have been changed to a capacity factor of only 30%. Again, wind is an outlier since its 30% utilisation is not by desire but by nature. And again, local cogeneration is the best option within the chosen boundary conditions. Nuclear power is the most expensive option now but coal firing for peaking power is also not very attractive. Notwithstanding the chosen high price level of natural gas, it remains a quite attractive fuel for electricity generators because of the relatively cheap equipment, high efficiency and low specific CO₂ emissions. The major restriction for using gas is supply insecurity problems, primarily originating from political issues. It is primarily the task of governments to solve such problems. Many countries are now working on building LNG reception terminals to diversify the sources of natural gas. Ultimately, gas-fired cogeneration is an effective value creator for electricity producers.

Table 17: Costs analysis of different electricity production concepts (30% utilisation).

Power plant type		nuclear	coal	GT CC	Wind offshore	Local cogen
Specific investment	€/kW	2500	1200	600	2100	700
Own capital	%	30	30	30	30	30
Profit rate	%	15	15	15	15	15
Bank interest level	%	5	5	5	5	5
Discount rate	%	8	8	8	8	8
System life	years	30	30	30	20	30
Utilisation factor	%	30	30	30	30	30
Construction time	months	60	45	36	6	4
Fixed charge rate	%	8.9	8.9	8.9	10.2	8.9
Specific capital costs	€cts/kWh	9.65	4.43	2.16	8.35	2.26
Fuel price	€/GJ	1	3.5	7	-	7
Gross fuel efficiency	%	46	46	57.5	-	44.5
System use	%	6	7	4	2	2
Net production efficiency	%	43.2	42.8	55.2	-	43.6
Specific fuel costs	€cts/kWh	0.64	2.27	3.52	-	4.46
Insurance premium	% investm.	1	1	1	2	1
Fixed annual costs	% investm.	0.9	1.3	1.7	0.8	2.1
Spec. maintenance	€cts/kWh	0.6	0.5	0.5	0.4	0.5
Total additional costs	€cts/kWh	2.41	1.54	1.12	2.62	1.33
CO ₂ price	€/ton	15	15	15	15	15
Specific CO₂ emissions	g/kWh	45	824	365	25	462
Specific CO₂ costs	€cts/kWh	0.06	1.24	0.55	0.04	0.69
Product costs (no cogen)	€cts/kWh	12.76	9.48	7.35	11.01	8.74
Cogeneration efficiency	%					85
Cogen benefit CO ₂	g/kWh	-	-	-	-	213
Net CO₂ costs	€cts/kWh	-	-	-	-	0.37
Cogen heat revenue	€cts/kWh					2.55
Total costs		12.76	9.48	7.35	11.01	5.78
Specific CO₂ cogen	g/kWh	-	-	-	-	249

There is a disturbing factor however created by the governments and gas companies. In tables 16 and 17, the gas price for electricity generation has been set at 7 €/GJ (lower calorific value), irrespective of the use in central power plants or local power plants. In many countries however, large differences exist in gas prices, due to a price level favouring large users and due to higher levies and VAT for domestic and commercial users only. Table 17 gives average gas prices for industry and for domestic use as valid in the year 2006. If we presume

that power stations pay the same rate as industrial users, the costs of gaseous fuel are substantially lower for large power stations than for e.g. micro cogeneration in homes. However, the electricity price rates are also much higher for domestic and commercial users, especially due to heavy taxation in some countries. Governments should apply a fair tax regime not favouring inefficient generation. With the prices indicated in table 18, domestic electricity generation with domestic natural gas is more attractive in Danmark than in Italy. Industrial cogeneration with gas looks quite unattractive in Deutschland with its high gas price for industrial users. Based on the limited available information here, it is difficult to evaluate the real effects of price structures and taxation on the economic possibilities of local generation.

Table 18: Average gas and electricity prices in the five selected EU countries (including all tax, year 2006) [29]

country	Industrial electricity	Domestic electricity	Industrial natural gas	Domestic natural gas
	€cts/kWh	€cts/kWh	€/GJ (HHV)	€/GJ (HHV)
Danmark	8.01	23.62	6.97	16.63
Deutschland	9.94	18.32	11.58	15.98
Italia	12.08	21.08	7.00	16.02
Polska	6.33	11.90	6.77	9.46
Portugal	8.17	14.10	7.63	14.52

8.7 Greenhouse gas emission aspects

Figure 29 gives the specific CO₂ emissions of all net electricity supplied in (g/kWh) [30] as well as for the electricity produced without wind, hydro and biomass [1]. Tables 16 and 17 give information that reveals the background of the differences. No discounting corrections have been made for cogeneration as in tables 16 and 17, because of the unknown efficiencies of the existing cogeneration installations. Danmark has relatively high CO₂ emission values notwithstanding the fact that over 16% of electricity originated from wind energy in 2004. Their coal-fuelled power stations are the main cause of this. A correction for cogeneration would certainly bring down the given specific CO₂ emissions. Nuclear power plants are the reason that the specific emission in Deutschland are lower than those of Danmark. Italy has many modern gas plants and uses much hydro, so it has the lowest CO₂ emission of the five countries selected. Polska is so high because of its many coal and lignite plants with very low fuel efficiency. Portugal has relatively much hydro, which pulls down the CO₂ emission level, but the coal-fuelled plants with a high utilisation factor make that the emission by non-renewables is 695 g/kWh. From an EU point of view, modernising equipment in Poland and using natural gas for peaking power are very effective steps in reducing CO₂ emissions. Also more gas-fuelled cogeneration especially in Deutschland and Italy will help to decrease emissions.

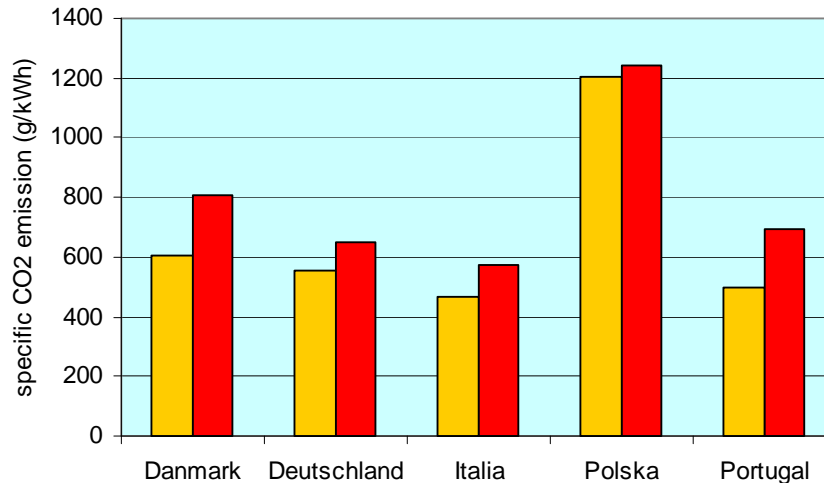


Figure 29: Specific CO₂ emissions from electricity production (ochre = for all electricity supplied; red = for electricity excluding wind, hydro and biomass) (2004).

The absolute value of reduced greenhouse gas emissions can only be evaluated on the long term. As long as emission reductions result from financially attractive energy savings and from fuel changes, one might speak of an indirect benefit. Sequestration of CO₂ in oil and gas wells can also be attractive since it can result in a higher output of those wells. However, emission reductions that cost money, such as sequestration in unproductive cavities, will have to be weighed against future costs to reduce negative effects of global warming.

8.8 The value of local generation for the government budget

Governments charge tax on the use of energy via special levies and VAT. Often, national governments participate in fuel production activities, while provinces and municipalities own or participate in electricity companies. In some cases, they also support activities such as coal mining with infrastructural measures. The author has tried to find the state income from energy use in the five countries under investigation but could not find it in the public domain. In Nederland, the government directly received the amount of 6.5 billion € from natural gas production in 2006. Although that is just 3% of the total government budget of 200 billion €, it is still a quite attractive sum of money for carrying out special political desires. Only 290 million was used for energy saving measures and 78 million for stimulating energy-related research. The costs of the civil servants co-ordinating these activities was 27 million €. Table 19 indicates the levies and charges on domestic electricity use as found in [1, 29] for the five countries under investigation plus Nederland. Nederland has been added because of the known annual government budget. The levies and charges on domestic electricity use amount to 1% of the government budget in Nederland. By comparing the total population per country, it is easy to see that in Danmark the relative government income from domestic electricity use is even higher. It is true that part of this taxation is fed back to the producers of renewable electricity, but according to figure 14 only up to 50% of the average electricity levy income is used for that. The VAT is direct income for the states and is not fed back for energy savings purposes. Based on the limited available information here, it is difficult to evaluate the exact effects of price structures and taxation. To illustrate the difficulty, [29,13] the German government received 12.68 billion Euro on levies excluding VAT. This can be split up in 0.81 G€ CHP levy, 6.60 G€ electricity tax, 3.18 G€ renewable energy levy and 2.09 G€ concession levy.

Table 19: Total of levies and VAT on domestic electricity use in six EU countries (2004) [1, 29]

country	levies	VAT	Total tax on domestic electricity	population
	million €	million €	million €	thousand
Danmark	922	507	1429	5398
Deutschland	2877	3622	6499	82532
Italia	2450	1278	3728	57888
Polska	114	467	561	38191
Portugal	124	74	198	10476
Nederland	1339	752	2091	16258

Table 20: Total of levies and VAT on gas for domestic and service as well as levies on gas for industrial use (gas quantity 2004, gas price 2006) [1, 29]

country	Total on gas for domestic & service	Total on gas for industry
	Million €	Million €
Danmark	748	100
Deutschland	7188	1100
Italia	6086	879
Polska	372	0
Portugal	10	0
Nederland	4110	792

The total tax on gas use is also considerable (table 20), especially in Nederland where most homes have individual gas heating. Nederland collects about 7 billion € of tax from energy use, in addition to the 6.5 billion revenues from gas production. The total is almost 7% of the government budget. For the Portuguese and Polish governments, energy use is hardly a source of income.

It is not easy in the context of this report to clearly reveal the direct financial impact of energy savings for the income of a government. Especially the Italian state transfers just a very small amount of its energy-use related income on the support of more efficient technologies. Taxation on energy use is a non-negligible source of income for governments, especially in the wealthier countries. They will probably make sure that their total budget will not be reduced. Governments and political parties in European countries generally act on a short term basis, from election to election, and a long-term vision and action plan such as needed for energy savings is rather passed on to another body like the European Commission. This is in strong contrast with China, where the government develops a series of successive five-year plans to safeguard the energy needs of the country with scenarios with a time span of more than half a century.

8.9 The impact of local electricity generation on security of supply

In an open market, the relative scarcity of goods, be it high-tech equipment or commodities such as fuels, determines the price. The huge positive leverage effect of fuel use for the economy is not by a long way reflected in the fuel price (see chapter 2). Growing economies are eager to secure their energy input and so are energy-based cultures such as in the USA. Currently, it is almost certain that any substantial reduction in energy supply in e.g. Europe will result in increase in use elsewhere. The need for more energy in China, India and America is that high that any small decrease in fuel price due to reduced consumption elsewhere will be followed by more consumption. The author is of opinion that any fuel savings in Europe will hardly have a positive effect on the long-term availability of fossil fuels (and on the global amount of greenhouse gas emissions).

Nevertheless, a more efficient use of fuels is of utmost importance for security of supply, since it makes the EU less dependent on fuel imports and its associated costs. The perspective that the EU has to import more than 75% of its energy needs is far from encouraging. It

makes the EU very vulnerable to restrictive actions by other countries. Therefore, not only equipment running on fossil fuels needs to have a better efficiency, but also that using renewable energy. Renewable energy is generally more costly than fossil fuel and a high efficiency helps to reduce the electricity costs. Too often, renewables are supported just for political reasons, even if their application is very costly and inefficient yet (solar photo voltaics, fuel cells on hydrogen and ethanol). In countries with large forests, electricity and heat can be produced with local installations fuelled by biomass. Efficient digesters of agricultural and other similar residues can produce gas for local generators, preferably again via cogeneration. Bio oils and fats are also suitable for energy efficiency cogeneration. Wind energy should be restricted to an annual total of 15% of the average electricity needs as long as temporary storage of electric energy is not more widespread. This is for reasons of controllability of the electricity supply system. Rapidly reacting local generators having a high efficiency are needed anyhow as a back-up for wind power.

One cannot state that measures that increase security of supply result in direct financial benefits. They can be compared with a defence army that is costly but it might safeguard economic activities in times of international disputes. In such a case, the value is very high. That's why intensified long-term research in efficient and environmental friendly energy resources is of utmost importance. Many technologies that are now used for fossil fuels, such as reciprocating engines and turbines, will also be needed to convert renewable energy sources into useable energy. Lately, policy makers have ignored existing conversion technologies and were focussing primarily on futuristic ideas. Local electricity generation with existing equipment is already able to save much primary energy via cogeneration and because of reduced transmission and distribution losses.

Of the five EU countries selected for this research, Deutschland and Polska are self supportive with respect to fuels for electricity generation. Apart from the 16% hydro in Italia and the 22% in Portugal, these two countries have to import all fuels for electricity generation. For the current consumption level, the reserve-production ratio for gas and oil in Danmark is 13 years, for lignite in Deutschland is roughly 80 years and for coal in Polska is 133 years. Polska is already installing some gas-fuelled generators, but the country fears supply security problems if a substantial amount of gas has to come from Russia. Deutschland is supporting its coal industry with about 2 billion € per year for reasons of job security as well as using indigenous fuel. Reference [32] expects that worldwide coal production will peak in 2025 and then slowly decline. The Chinese government revealed that most of their coal will be converted to CO₂ by 2050.

8.10 Effect of generating equipment costs on the national trade balance.

Generating equipment has to be renewed anyhow, although currently old equipment stays in use because of uncertainties for investors. By presuming equipment life exceeding 30 years and no substantial increase in demand, on average 3% of generating capacity has to be renewed per year. As an example, table 21 gives a possible mix of generating methods resulting in an average investment of 1730 €/kW. This mix will result in 20% electricity production from renewables.

Table 21: A possible generator mix for replacing existing equipment (see also table 1)

technology	Fraction of El-production	Specific capital costs
	%	€/kW
Natural gas (local+ cogen+ GTCC)	40	650
Nuclear	20	2500
Coal/steam	20	1200
Wind (50% offshore, 50% onshore)	10	4800
Local biomass	5	3000
Central biomass	5	2000
total	100	

Table 22: Replacement costs of generating equipment for the 5 countries (presumed average investment 1730 €/kW; capacity in 2004, trade for 2006 from Eurostat)

country	Generating capacity	3% yearly replaced	10% yearly replaced	Total exports	Total imports
	GW	G€	G€	G€	G€
Danmark	13.4	0.70	2.3	74	69
Deutschland	123.8	6.43	21.3	886	722
Italia	81.3	4.22	13.9	325	348
Polska	31.7	1.65	5.4	88	81
Portugal	12.7	0.66	2.2	35	49

Table 22 reveals that a gradual 3% replacement of existing generating equipment under conditions of business as usual using the equipment mix as given in table 16 requires an investment that lies between 0.8 and 2% of the total imports value. This is in case we presume that the complete facilities have to be imported. The lowest fraction of import value applies for Deutschland and the highest for Polska. These replacement costs are at least a factor two lower than the annual fuel costs for electricity generation (compare table 14). Replacing only 3% of generating equipment per year gives a very slow path towards having equipment with a maximum efficiency. If 10% of equipment is replaced per year, the burden on the balance of trades becomes much higher, e.g. 6.7 % of the import value of Polska. If this measure would ultimately result in 40% net supply efficiency instead of the current 23.8 %, the fuel input for electricity generation in Polska would be 40% less than what it is today. However, the first year it would be only 4% less, resulting in fuel costs of 8.7% of the total imports value instead of 9.1%. This means that a rapid replacement by more efficient equipment is not immediately cost effective if we only consider the fuel costs and investment costs. However, on the long term, a fast upgrading of generating equipment will save much fuel and reduce much emission. With respect to the balance of trade, the problem is even worse since Polska has to import technology but most of its fuel is indigenous. Replacing Polska's old coal-fired equipment by the generating mix as given in table 16 would reduce its specific CO₂ emissions by about a factor three. Anyhow, if Poland and to a lesser extent Portugal will approach the wealth level such as in the West European countries, much new capacity has to be installed anyhow. Portugal has chosen a proper approach; it requires that the bulk of production of the equipment needed for a substantial amount of wind energy is carried out in Portugal itself. Such an approach is however not practical for capital intensive manufacturing equipment such as needed for turbines and reciprocating engines.

9 Summarising conclusions

9.1 General conclusions

1. The value of electricity is very high for modern economies. Electric energy enables the use of highly productive manufacturing and data-handling technologies. In the EU-25, industry creates between 0.5 and 3 € of GDP per kWh of electric energy (the average is 2€/kWh) and the service sector creates between 1.5 and over 100 € of GDP/kWh (the average is 10 €/kWh). Without a reliable supply of electricity, the EU economy will grind to a halt. Expectations are that electricity use in the EU will increase at least by 2% per year during the next 25 years [33], especially caused by catching up of GDP/capita in the East European states.
2. The long-term value of fuels is by far not reflected in a high fuel efficiency of the electricity sector. The average fuel efficiency of net electricity supply in the EU-25 is only about 31.5% for all fossil fuelled installations. The gross fuel efficiency of electricity production based on fossil fuels is 38%. The difference between gross and net fuel efficiency is caused by system use and network losses. A better fuel efficiency of the electricity sector is especially important since the sector uses about 36 % of total primary energy supply and is therefore the single largest fuel consuming sector. About twelve percent of electricity use in the EU-25 comes from renewables now, including large-scale hydro.
3. A better fuel efficiency of the electricity sector can be reached by installing efficient generating equipment closer to the users as well as by better handling of the dynamics in demand of electricity users. Rapidly reacting units can serve to cover the peak loads and to provide system services. Cogeneration, i.e. using the heat released during the electricity generating process, is the most cost-effective means for fuel utilisation improvement and for decreasing specific CO₂ emissions. In cogeneration applications, over 85% fuel efficiency can be reached.
4. Local electricity generation does much more justice to the intrinsic value of fuels. Local electricity generation with natural gas as a fuel and/or with renewables such as biogas and liquid biofuels can have a fuel efficiency of net electricity supply of close to 44% in simple-cycle mode and close to 50% in combined cycle mode. A recent study shows that technology improvements can raise this to close to 55% [Dessau paper]. Reciprocating engines are prime movers that can instantaneously switch over from one fuel to another, thus creating flexibility in times of scarcity or supply problems of a particular fuel.
5. Electricity from wind power is very welcome since it is (close to) fuel free. However, the typical character of wind makes that the average utilisation factor of wind-powered generators ranges between 20% and 30%, while the output is not predictable. Wind-based generation capacity does not reduce the total amount of other generating capacity needed so that ultimately the specific capital costs of the non-wind generators increase. Producing over 10% of the annual electricity demand with wind power can cause problems with system balancing and control, especially in times of low demand, if no temporary storage and rapid back-up capacity is present.
6. Electricity generation by photo voltaic systems should not be promoted as long as the production costs of the units are so high and the efficiency is so low. Moreover, such units cannot produce electricity in times of maximum demand in the evening of winter days so that the amount of other generators cannot be decreased. However, using solar irradiation on the long run is an unavoidable option. Therefore, research into better PV systems (and electricity storage systems) should be directly stimulated by the EU to a much larger extent.
7. Hydro-based systems offer effective options for temporary, indirect, storage of electrical energy with an efficiency of about 85%. Storage via the hydrogen – fuel cell route requires excessive investments and has a very low efficiency of about 25%.

8. Electricity supply reliability is much higher with a large number of smaller units in parallel and close to the user than with a few large generators with long transmission and distribution lines. That is the reason why local generators running in parallel with the grid are already common practice for sensitive applications such as hospitals, airports, data-handling centres and military bases.
9. Base-load electricity generation (85% utilisation factor) costs about the same for nuclear, coal-fired or gas-turbine combined cycle installations, notwithstanding gas being a factor two more expensive than coal. For peaking power, gas fuelled engine or turbine driven installations are the cheapest option. Local cogeneration installations produce the cheapest electricity of all alternatives.
10. The low capital costs of existing, written off, coal-fired and nuclear power stations as well as uncertainties about future fuel supplies and costs hamper a rapid innovation in European generating capacity.

9.2 Specific conclusions from the five countries analysis

1. There are large differences between the five countries in energy intensity and electricity intensity. The poorest country, Polska needs about 19 MJ of primary energy to create one Euro in gross domestic product while the richest country, Danmark, needs about 3.9 MJ/€. With respect to electricity use, Polska uses about 0.5 kWh per Euro in GDP while Danmark needs just 0.15 kWh/€. Although the purchase power parity of the Euro is a factor 2.4 higher in Polska than in Danmark, the high specific energy use of the Polish economy is unsustainable and a barrier for a rapid growth of the economy. Italia is the middle bracket, Portugal is between Italia and Polska, while Deutschland is between Danmark and Italia with respect to specific electricity use.
2. The fuel efficiency of net electricity supply is the lowest in Polska with just 23.8%, compared with 38% in Italia that has the best performance. Danmark unexpectedly has only 34% efficiency but that is compensated to some extent by a large amount of cogeneration (50%). None of the five countries reaches the 44 % efficiency that is possible with the proper modern generation mix including much local electricity generation.
3. Covering the annual electricity demand in a country for more than 15% by wind energy creates grid instability and control problems if no substantial buffer capacity (hydro storage) or export opportunities are available. One might consider the use of electrical heating in case of excessive wind energy. However, to be competitive with a domestic gas price of 16 €/GJ, the price of such electricity should be about 6 €/kWh. That is generally less than what a wind generator owner receives for his electricity.
4. Four of the five countries (Danmark excepted) have just little cogeneration while there is much potential, also in industry in Italia and Portugal.
5. The fuel costs for electricity production vary between 0.5% and 2.7% of GDP, depending upon the country. Deutschland has the lowest relative fuel costs and Polska the highest. The monetary value of the fuel amounts to 9% of the total imports in Polska and just 1.9% in Danmark.
6. The burden of electricity use on the household budget ranges between 1.6% and 2.5% of the average net household income. The highest value applies for Danmark and the lowest for Deutschland.
7. Governments in the wealthier countries (Danmark, Deutschland, Italia) receive at least an estimated 2% of their annual budget via levies and taxes on electricity. There is insufficient transparency on EU level about how much of these taxes are used for stimulating technology improvements as well as renewable energy. Also the effectiveness of the support mechanisms is not clear.

9.3 Typical conclusions related with the value issue.

1. The values of local generation differ from technology to technology. Electricity derived from wind and solar radiation has a fully different impact on the electricity system than that of gas-fuelled equipment or units running on bio mass.
2. The costs of electricity for the end user can be lower if more local generation will be used, due to a better efficiency and less investments.
3. The reliability in terms of less power outages can be improved if more dispatchable local generation will be used.
4. The amount of greenhouse gas emissions can be drastically reduced if a substantial amount of local generation is used.
5. Both short-term and long-term security of supply will improve if the electricity sector uses more local generation resulting in higher fuel efficiency and thus less fuel consumption.
6. Governments generally receive a noticeable amount of budget income from energy transactions based on fossil fuels so that a better fuel efficiency as well as support mechanisms for renewables will reduce their income.
7. Fuel supply companies will sell less fuel and therefore receive less income in the short term in case of high fuel efficiencies.
8. Power companies can benefit from lower fuel costs and state-support mechanisms in case of local generation provided they are involved in it.
9. Grid operators can derive value from some types of local generation based on their adequate properties for providing system services. Grid owners can sometimes benefit if an expansion of the grid can be avoided by local generation capacity. However, in many case, ideal sites for local generation need additional grid capacity since the grid is too weak to transport the electricity that is not locally consumed. Moreover, local generation can interfere with existing voltage control and fault detection equipment so that additional investments are required.
10. The value of wind and solar power can be increased with a hybrid approach using suitable parallel generating equipment of a dispatchable nature running on fossil or renewable fuels.
11. National trade balances can benefit from reduced fuel costs in case of more efficient local generation.
12. The EU manufactures all the products needed for efficient local generation. A strengthened home base for the products will increase the competitiveness of the EU industries.
13. It is close to impossible to express all values of local generation in general absolute money terms. That can only be done for defined cases with sufficient transparency of the different interests of the various stake holders. The ultimate intrinsic value of energy-efficiency improvements will only be revealed in times of higher scarcity of primary energy. That is the law of economics. It is certain that these times will come sooner for Europe than many expect.

References

- [1] Eurostat, '*Energy: yearly statistics – data 2004*', Office for Official publications of the European Communities, ISSN1609-4190, 2005
- [2] International Energy Agency, '*Key World Energy Statistics*', Paris, 2005
- [3] Vuorinen, Asko, '*Planning of Optimal Power Systems*', ISBN 978-952-1741-0, Espoo, 2007
- [4] Meier, Hans-Joachim, 'Role of Electricity – Fossil fuel based Technologies', Eurelectric Workshop II, Brussels, 23 November 2006
- [5] Datamonitor, 'Utility Market Drivers: Technology', BFEN 0186, July 2006
- [6] Scialdoni, Raffaele et al, 'Renewable energy sources and their competitiveness with conventional sources', ASME Conference Energy: production, distribution and conservation, Milan, May 14-17, 2006.
- [7] Deffeyes, K.N., '*Hubbert's peak – The Impending World Oil Shortage*', Princeton University Press, Princeton, NJ, 2001
- [8] Anonumus, 'Arctic Role Diminished in World Oil Supply',
- [9] E-coal magazine, January 2007.
- [10] Information page 48, Pipeline and Gas Journal, February 2007
- [11] Transmission and natural gas compared
- [12] Tennet, Tarievenblad%20150%20kV-110%20kV%202006_tcm41-12736.pdf
- [13] http://epp.eurostat.ec.europa.eu/cache/ITY_OFFPUB/KS-NQ-06-018/EN/KS-NQ-06-018-EN.PDF
- [14] Proceedings of the 2006 China International Conference on Electricity Distribution CIED2006, Beijing, China, 17-20 September 2006
- [15] Two-day course on the integration of distributed generation, University of Eindhoven , The Netherlands, November 21 and 22, 2006
- [16] Data from the website of Scottish Power, www.scottishpower.com
- [17] Baxter, Richard, '*Energy Storage*', Pennwell Corporation, Tulsa, Oklahoma, ISBN 1-59370-027-X, 2006
- [18] Lysen, Erik et al, 'Opslag van elektriciteit: Status en toekomstperspectief voor Nederland', report Projectnummer NEO 0268-05-05-01-002, Utrecht Centre for Energy Research, September 7, 2007
- [19] via google: doc.ic.ac.uk
- [20] see Power Engineering International magazine, September 2004
- [21] 'Life is a biogas', Power Engineering International magazine, p.43, March 2007
- [22] Distributed Generation: Policy Framework for Regulators, White paper, prepared by Arthur D. Little, Cambridge, MA, 1999
- [23] Bolt, N. et al, State of the art studie techniekontwikkeling voor de elektriciteitsvoorziening, report 40560104-TDC 06-55631A, Kema T&D Consulting, February 10, 2006
- [24] http://www.esru.strath.ac.uk/EandE/Web_sites/98-9/grid_connected_pv/lca.htm
- [25] <http://www.uic.com.au/ComparativeCO2.htm>
- [26] Gipe, Paul, '*Wind Energy Comes of Age*', John Wiley and Sons, 1995
- [27] Loesonen, Pekka and Adriana Opris, 'Combined Heat and Power (CHP) in the EU, Bulgaria, Romania and Turkey – 2004 data', Eurostat_CHP_stats_2004.pdf
- [28] Esdaile-Bouquet, Thomas, 'Overview of CHP in Europe – A country-by-country study', Report from Cogen Europe, Brussels, July 2005
- [29] Eurostat, 'Gas and electricity market statistics', Data 1990-2006, ISSN 1830-0472, 2006
- [30] Eurelectric, 'Statistics and prospects for the European electricity sector (1980-1990, 2000-2020)', EURPROG Statistics Electricity EU .pdf
- [31] COSPP Volume 8, nr 2, April-May 2007
- [32] Energy Watch Group, 'COAL: RESOURCES AND FUTURE PRODUCTION', EWG-Series No 1/2007, Final-Version 28032007, March 2007
- [33] IEA, '*World Energy Outlook*', Paris, 2006.

[34] Klimstra J, 'The road to obtaining the ultimate performance of gas engines – opportunities and challenges', 5th Dessau Gas Engine Conference, March 29 – 30, 2007, Dessau, Saxony-Anhalt, Germany

Additional general literature used

Carol A. Dahl, '*International Energy Markets*', ISBN 0-87814-799-3, PennWell Corporation, Tulsa, Oklahoma, 2004.

Walt Patterson, '*Transforming Electricity*', ISBN 1 85383 341 X, Earthscan, London (UK), 1999.

Amory B. Lovins, '*Small is Profitable*', [ISBN 1-881071-07-3, Rocky Mountains Institute, Snowmass \(CO\), 2002.](#)

Wolfgang Jörss et al, '*Decentralised Power Generation in the Liberalised EU Energy Markets*', ISBN 3-540-40133-4, Springer Verlag, Berlin, 2003.

APPENDIX

Country name translation list

The author of this report has used the official names of the EU-25 countries in this report. This is based on the conviction that a profound interest in the typical aspects of each member country is needed for understanding the energy and economic situation specific to each country.

Official name	English equivalent
België/La Belgique	Belgium
Ceska	Czech Republic
Danmark	Denmark
Deutschland	Germany
Eesti	Estonia
Ellada	Greece
España	Spain
La France	France
Ireland	Ireland
Italia	Italy
Kypros	Cyprus
Latvija	Latvia
Lietuva	Lithuania
Luxembourg	Luxemburg
Magyarország	Hungary
Malta	Malta
Nederland	The Netherlands
Oesterreich	Austria
Polska	Poland
Portugal	Portugal
Slovenja	Slovenia
Slovensko	Slovakia
Suomi/Finland	Finland
Sverige	Sweden
United Kingdom	United Kingdom

List of conferences, workshops and courses attended in connection with the ELEP WP 3 work

Past:

1. February 23-24, 2006, European Power Symposium, Rome
2. April 24, 2006, European Biopower Meeting, Hannover
3. April 28, 2006, European cogen course, Kortrijk
4. May 15-17, 2006, ASME ATI conference on Energy production, distribution and conservation, Milano, Italia.
5. May 25 – 26, 2006, ICCS, Cogen conference, Istanbul, Turkey
6. May 30 - June 1, 2006, Powergen Europe, Cologne.
7. September 5-7, 2006, Asia & China Power, Hong Kong.
8. September 16-20, 2006, CISED Distribution conference, Beijing
9. September 25 – 26, 2006, Engine conference, Poznan, Poland
10. Oktober 12, 2006, CEE2006 European Power Conference, Warsaw.
11. October 30-31, 2006, WADE conference, Prague

12. November 3, 2006, Workshop: Co-Generation Units – balance between demand and offer, Bucuresti, Romania
13. November 15-16, 2006, Energy Security Conference, London
14. November 21 and 22, 2006, Course on the integration of distributed generation, University of Eindhoven, The Netherlands,

Future:

15. May 9-10, 2007, Annual Cogeneration Conference, Brussels
16. May 21-24, 2007, International distribution conference CIRED, Vienna
17. May 30-31, 2007, ICCI generation conference, Istanbul, Turkey
18. June 14, 2007, Cogen workshop, Sofia, Bulgaria
19. June 26-28, 2007, PowerGen Europe, Madrid, Spain
20. November 12-15, 2007, World Energy Conference, Rome, Italy

Papers, presentations and publications on the ELEP subject by Jacob Klimstra

1. 'Developments in generation technologies: the need for high efficiency and flexibility', The European Power Symposium, February 23-25, 2006, Rome, Italy
2. 'COGENERATION IN MODERN HOSPITALS', Russia Power Conference, 14th – 16th March 2006, Moscow, Russia
3. 'PERFORMANCE OF NATURAL-GAS-FUELED ENGINES HEADING TOWARDS THEIR OPTIMUM', Paper ICES2006-1379, Proceedings of ICES06, 2006 ASME Internal Combustion Engine Division Spring Technical Conference, May 7-10, 2006, Aachen, Germany
4. 'Cogeneration and Distributed Generation in the Cascade Mode: maximum efficiency and reliability', ASME-ATI Conference: Energy Production, Distribution and Conservation, May 14-17, 2006, Milano, Italy
5. 'Developments of Reciprocating Gas Engines for Decentralised Electricity Generation', ICCI 2006 Conference, May 25-26, 2006, Istanbul, Turkey
6. 'Heat-production control with reciprocating-engine-driven power plants', POWER-GEN Europe 2006, 30th May- 01st June 2006, Cologne, Germany
7. 'Dual-fuel generators: a possibility to improve efficiency and to decrease sensitivity to volatile boundary conditions', Carilec Engineers Conference, July 24 - 26, Trinidad and Tobago.
8. 'Cascading: a New Approach to Electricity Generation in the Distribution System with Maximum Efficiency and Availability as well as Minimum Costs', 2006 China International Conference on Electricity Distribution, September 16 - 20, 2006, Beijing
9. 'The Performance of Cogeneration Gas Engines in the Power Range 5 - 17 MW', Natural Gas Conference, Poznan University of Technology, September 26-26, 2006, Poznan, Poland
10. 'The current state of electricity supply and a way for improvements', CEE Conference POWERING THE ECONOMIC REVIVAL, 12 October 2006, Warsaw, Poland
11. 'Life-cycle costs of power plants and maintenance considerations', CEE Conference POWERING THE ECONOMIC REVIVAL, 12 October 2006, Warsaw, Poland
12. 'The effect of generator sizing on electricity generating efficiency and reliability: the advantages of local generation', WADE Conference, October 30-31, 2006, Prague
13. 'Cogeneration and Cascading with Reciprocating Engines: a High Fuel Efficiency and Supply Reliability at Lower Costs', Workshop: Co-Generation Units – balance between demand and offer, November 3, 2006, ISPE, Amfiteatru Hall, Bucuresti, Romania
14. 'RETHINKING THE DISTRIBUTION CONCEPT – the benefits for developing countries as well as developed countries', Paper T3-357, CEPSI 2006, The 16th Conference of the Electric Power Supply Industry, 6-10 November 2006, Mumbai, India
15. 'Power in Numbers – why multiple, decentralized power plants are better', COSPP Cogeneration & On-Site Power Production, Vol. 7, Nr. 5, September –October 2006.
16. 'Local electricity generation: an evaluation of its values for the distribution of electricity', CIRED Conference, May 21-24, 2006

17. 'Reliable Power from Renewables with Assistance from Reciprocating Engines', PowerGen Europe 2007, Madrid, España, June 26-28
18. 'Local and central generation: Efficiency improvement via a hybrid approach', ICCI Conference, May 30-31, 2007, Istanbul, Turkey
19. 'The need for efficient and cost effective peaking power plants in a modern electricity supply system', PowerGen Asia, Bangkok, Thailand, September 4-6, 2007
20. 'The Need for a Higher Fuel Efficiency of the Electricity Sector – An Analysis of Opportunities and Barriers', World Energy Conference, Rome, Italy, November 11-15, 2007