Ministry of the Economy of the Republic of Lithuania

Analysis of high-capacity cogeneration potential in Lithuania and adoption of necessary methodologies or other legal instruments required for full implementation of Directive 2004/8/EC of the European Parliament and of the Council

15 December 2005

COWI
Baltic

In cooperation with
Termo Sistem• Projektai

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UAB COWI Baltic Lukiški• 3 Vilnius 2600 Phone: +370 5 2107623 Fax: +370 5 2124777 E-mail: info@cowi.lt Account no: P-25034E-01 Permit No: 01 Publishing date: 21 10 2005 Prepared by: DB / LN / GZ / NR Checked by: GZ/NR Approved by: GZ/NR	**UAB Termosistem• projektai** Gedimino g. 47 LT-44242, Kaunas Phone: +370 37 207222 Fax: +370 37 207137 E-mail: tsp@tsp.lt

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1 Introduction

Directive 2004/8/EC of 11 February 2004, promoting combined production of heat and power in the domestic markets of EU Member States, came into force in March 2004. The Directive aims:

- *to increase energy efficiency and improve security of supply by creating a framework for promotion and development of high efficiency cogeneration of heat and power based on useful heat demand and primary energy savings in the internal energy market, taking into account the specific national circumstances especially concerning climatic and economic conditions.*

The Directive must be implemented in the Member States over a two-year period. During this period, the Commission must supply the Member States with clear guidelines and all the information necessary to ensure compliance of national legislation with the Directive.

The objective of this study is to work out a methodology for the calculation of electricity resulting from cogeneration of heat and power, to carry out an analysis of the potential for high-efficiency cogeneration potential in the country, to examine the legislation governing cogeneration and to propose improvements to this legislation.

The report consists of four parts:

- Analysis and review of the current situation, covering the technologies used by national cogeneration plants, determination of the ratio of their nominal power and heat capacities, data on the quantities of power and heat generated by each cogeneration plant, the structure of fuel consumption and the amount of fuel consumed;
- Adoption of a methodology for the calculation of the electricity produced as well as for the establishment of the efficiency of the cogeneration process in accordance with Annexes II and III to Directive 2004/8/EC;
- Analysis of the national potential for high-efficiency cogeneration of heat and power;
- Analysis of the legislation governing cogeneration and proposals regarding the improvement of the said legislation.

2 Summary

The objective of the study is to carry out an analysis of all the cogeneration plants operating in the country, to estimate the technical and economic potential for combined heat and power, and to identify technical, economic as well as administrative barriers to the realization of the said potential.

Chapter 3 and Annex 2 present comprehensive data on the cogeneration plants operating in the country.

Chapter 4 presents the methodology for the estimation of electricity from cogeneration as well as efficiency of the cogeneration process:

- The methodology for calculation of electricity from cogeneration in accordance with Annex II of Directive 2004/8/EC;

- The methodology for calculating the efficiency of combined heat and power in accordance with Annex II of Directive 2004/8/EC.
- **Chapter 5** deals with the country's technical and economically justified combined heat and power potential. It also offers fuel price forecasts as well as a review of cogeneration unit technologies, investment and operation.

In 2004, the total internal electricity consumption amounted to 12.1 TWh, while total production came to 19.3 TWh. Total heat consumption (generation) amounted to 15.2 TWh.

According to the latest forecasts for the main scenario, the country's electricity demand in 2020 will amount to 15.5 TWh or, in the case of rapid economic growth, to 17 TWh. The demand for heat will grow very insignificantly, as connection of new consumers is made up for by measures improving energy efficiency: the estimated heat demand in 2020 will total 18 TWh under the main scenario and 20 TWh under the scenario of rapid economic growth.

A hike in natural gas prices, up to EUR 183.1/toe (LTL 569/thou nm^3), is anticipated as of 1 January 2006. Subsequently, natural gas prices are expected to climb by approximately 1% per year, reaching roughly EUR 198.6/toe (LTL 617/thou nm^3) by 2025. The price of high sulphur content fuel oil (>1% S), which increased over the recent years due to the hike in oil prices, should go down to EUR 145/toe (LTL 477/t) but is expected to resume growth later, during the period until 2025, at a pace similar to that of natural gas prices, i.e. roughly 1% per year. In that case, the price of high sulphur content fuel oil should total around EUR 161/toe (LTL 528/t). Forecasting the prices of fuel oil with low sulphur content (<1% S) is even more difficult, as the possibilities of producing and importing it are yet unknown. However, the price of this type of fuel oil may be 20-50% above the price of high sulphur content fuel oil. Growth in wood fuel prices, which was remarkable in the 2003-2005 period, is expected to slow down. Before 2025, the prices of this type of fuel are likely to edge up 1.4% per year. The price of wood fuel, which amounted to EUR 98.2/tne (LTL 338/tne) during quarter I-III of 2005, should reach EUR 126.5/tne (LTL 437/tne) by 2025.

Listed below are investments in cogeneration plants and their operating costs.

Table 2-1. Summarized total relative costs of construction of cogeneration plants

No	Type of main unit of cogeneration plant	Installed capacity, MW_{el}	Relative project price €/kW_{el}	Price used in analysis, €/kW_{el}
1.	Internal combustion engine	0.5-5.0	750-900	825
2.	Gas turbine	5.0-40.0	650-1000	825
3.	Steam turbine + boiler (biofuel)	0.6-50	3500-5700	4600
4.	Combined cycle	10.0-100.0	680-1180	930

Table 2-2. Standard total operating costs of cogeneration plants

No	Type of main unit of cogeneration plant	Installed capacity, MW_{el}	Operational costs, €/MW_{el}	Costs value used in analysis, €/kW_{el}

1.	Internal combustion engine	0.5-5.0	6-11	8.5
2.	Gas turbine	5.0-40.0	4-8	6
3.	Steam turbine + boiler (biofuel)	0.6-50	2-4% of investment per annum	14.2*
4.	Combined cycle	10.0-100.0	3.25-5.4	4.3

* Note: accepted operation time of units is 8 000 hrs per year.

The installable technical potential for electricity production (see below) totals 881 MW for gas and 50 MW of biofuel.

Instaliuotina elektros energijos gamybos galia, MW – Installable electricity production capacity, MW

Šilumos energijos poreikio gali• ne šildymo ir pereinamajame sezone vidurkio intervalai, MW–
Intervals of the average heat demand capacities outside the heating season and during the transitional season, MW

n•ra gamtini• duj• (biokuras) – without natural gas (biofuel)

yra gamtin•s dujos – with natural gas

Viso: gamtin•mis dujomis – 881 MW; biokuru – 50 MW – *Total*: natural gas – 881 MWh; biofuel – 50 MWh

Fig. 2-1. Installable electricity production capacity in the Lithuanian district heating sector, excluding the integrated systems of Vilnius and Kaunas cities

The annual technical potential for electricity production in the district heating sector, as illustrated below, totals 4 014 249 MWh for natural gas and 214 499 MWh for biofuel.

Metin• elektros energijos gamyba, MWh – Annual electricity production, MWh

Šilumos energijos poreikio gali• ne šildymo ir pereinamajame sezone vidurkio intervalai, MW–
Intervals of the average heat demand capacities outside the heating season and during the transitional season, MW

n•ra gamtini• duj• (biokuras) – without natural gas (biofuel)

yra gamtin•s dujos – with natural gas

Viso: gamtin•mis dujomis – 4 014 249 MWh; biokuru – 214 499 MWh – *Total*: natural gas – 4 014 249 MWh; biofuel – 214 499 MWh

Fig. 2-2. Annual technical potential for electricity production in the district heating sector, excluding the integrated systems of Vilnius and Kaunas cities

The actual economically substantiated cogeneration potential amounts to 610.9 MW in CH systems that can use natural gas and 43.9 MW in systems that contain no natural gas.

Installed thermal power amounts to 645.6 MW in district heating systems that can use natural gas and to 115.4 MW in those that cannot. The total annual quantity of produced heat amounts to 2 830.52 GWh (when the fuel used is natural gas) and to 178 GWh (when the fuel used is not natural gas). The investment requirement in order to fully utilize the cogeneration potential is LTL 1 847 454 000 for CH systems that use natural gas fuel and LTL 697 353 000 in CH systems that contain no natural gas.

Taking into account the quantity of energy generated for the domestic market in 2004, 12.1 TWh, and the fact that the additional electricity generated, on the basis of combined cycle, by the new cogeneration units planned in Kaunas would amount to 600 GWh annually, it may be stated that the current national combined heat and power production together with the yet unused combined heat and power potential would account for roughly 57% of total electricity production for the domestic market.

The main barrier to effective development of high-efficiency cogeneration plants in the country is the current market price of electricity, which is influenced by the marginal costs of short-term electricity production at the INPP. However, this barrier no longer needs to be taken into account, since the situation will change after 2010, when Lithuania will have fulfilled its obligations regarding the decommissioning of Unit II of the INPP.

In relation to utilization of the cogeneration potential, no technical barriers have been found, apart from the insufficient natural gas pressure in the case of construction of combined cycle systems.

Chapter 6 contains an analysis of the legislation governing cogeneration. The country has no artificial administrative barriers to combined heat and power production; a system for support and promotion of such type of production is in place. Support for combined heat and power production is extended via a quota system by treating the electrical energy produced on the basis of quotas by cogeneration plants as a public interest. The main problems encountered by all those who intend to build new cogeneration plants are some uncertainties within the quota fixing system, the procedure of connection to the existing power and natural gas systems as well as taxes.

Chapter 7 briefly outlines the principles of promoting cogeneration plants in other countries.

Chapter 8 presents recommended provisions for the National Energy Strategy in relation to the implementation of Directive 2004/08/EC.

3 Analysis of cogeneration plants operating in the country

33 enterprises were surveyed with the aim of obtaining an overview of the existing cogeneration plants (CPs) in the country. 23 enterprises responded.

Extensive data on the cogeneration plant technologies and equipment, power and heat production, fuel consumption efficiency, power-to-heat ratios as well as primary energy savings are presented in Annex 2. This chapter presents the indicators summarizing the above-mentioned data.

At present, major cogeneration plants operate in the cities of Vilnius and Kaunas and are capable of supplying all the heat required by district heating systems. Lower-capacity cogeneration plants are found in the district heating systems of Klaip•da, Panev•žys and other major towns of the country. However, their heat production capacities are insufficient to satisfy the heat requirements of the respective towns. Elektr•nai town has a 1 800 MW electric capacity condensation power plant, yet, in view of the existing thermal scheme, it may be considered to be a cogeneration plant capable of producing heat in any of its energy units to meet the heating needs of Elektr•nai town.

The operation of the two largest cogeneration plants, located in Vilnius and Kaunas, began in 1984 and 1976, respectively. They are the largest heat producers in the two cities. Significant development of low- and medium- capacity cogeneration plants has been recorded since 2000. The breakdown of cogeneration plants based on installed electric capacity is illustrated by Table 3-1.

Table 3-1. Breakdown of cogeneration plants operating in Lithuania according to electric capacity

CP categories by nominal electrical capacity	Category description	Number of power plants .	Total installed electric capacity, MW	Share in total installed capacity, %
up to 1 MW_{el}	very low capacity	15	4.4	0.2
from 1 MW_{el} to 5 MW_{el}	low capacity	9	21.5	0.8

from 5 MW_{el} to 50 MW_{el}	medium capacity	5	88.5	3.3
above MW_{el}	high capacity	4	2 540.0	95.7
Total		33	2 654.4	100

Note. Divided into categories according to electric capacity pursuant to Resolution No O3-84 of 29 July 2004 of the National Control Commission for Prices and Energy.

The observed CP development in different branches of the Lithuanian economy has not been consistent either. The major part of the initiative in setting up CPs has so far come from district heating enterprises as well as larger industrial companies. However, the electric capacities of the installed power stations are not high because they are usually oriented towards an enterprise's capacity required during the minimum load period. CP distribution among branches of economy is presented in table 3-2.

Table 3-2. Development of cogeneration plants by economic sector

Branch of economy	Number of power plants	Share, %
District heating enterprises	19	58
Industrial enterprises	10	30
Agricultural enterprises	2	6
Public institutions	2	6
Total	33	100

It should be noted that the initiative in setting up low-capacity cogeneration plants is primarily demonstrated by businesses looking for possibilities of meeting energy demands with lower costs. Meanwhile, budgetary institutions as well as owners of big structures (hospitals, schools, administrative buildings) are rather reluctant to make use of this opportunity.

3.1 National cogeneration plant technologies and their compliance with the types specified in Directive 2004/8/EC

The breakdown of cogeneration plants by type of technology is presented in Table 3-3. The technology types shown in this table correspond to the list of technologies given in Annex I to Directive 2004/8/EC of the European Parliament and of the Council.

Among cogeneration plants set up after the year 2000, power stations with internal combustion engines are the predominant type (16 power stations). Industrial enterprises normally use CP systems with backpressure steam turbines, especially when technological steam is required. At the time of report presentation (February 2006), a gas turbine was used only by the cogeneration plant located in AB Achema. There are no combined cycle CPs in Lithuania, although there are plans to build one in Panev•žys.

Table 3-3. Breakdown of cogeneration plants according to type of primary engine

Cogeneration plant technology	Technology class according to EU Directive 2004/8/EC	Number of power plants	Share, %
Steam backpressure turbine	b	10	30.5
Steam condensing extraction turbine	c	6	18
Gas turbine with heat recovery	d	1	3.5
Internal combustion engine	e	16	48

Annex 2 presents extensive descriptions of individual cogeneration plants as well as the essential technological diagrams.

3.2 Nominal power-to-heat capacities (energy) ratio of separate units of cogeneration plants

The efficiencies of cogeneration plants, values power-to-heat ratio as well as estimation of primary energy consumption are given in Table 3-4.

Primary energy savings (PES) values were calculated base on the requirements set out in document 34. The established coefficient of performance values of electric and heat production applicable to Lithuanian cogeneration plants are listed in Chapter 3 of Annex 2.

Table 3-4.

Cogeneration	Technology class according to EU Directive 2004/8/EC	Cogeneration plant efficiency coefficient (lowest ÷ highest)/ average	Power-to-heat ratio (lowest ÷ highest)/ average	Primary energy savings (PES) (lowest ÷ highest)/ average
Steam backpressure turbine	**b**	(75÷85) / 80.9	(0.03÷0.26) / 0.10	(14÷5)/-4
Steam condensing extraction turbine	**c**	(31÷85)/53.4	(0.25÷0.83) / 0.54	(-66÷18)/-22
Gas turbine with heat recovery	**d**	72.0	0.70	5
Internal combustion engine	**e**	(69÷90) / 79.3	(0.40÷0.90) / 0.68	(-4÷28)/ 17

3.3 Quantities of electricity and heat generated at the country's cogeneration plants and the structure and quantities of consumed fuel

The quantities of electricity and heat generated at cogeneration plants as well as fuel consumption in 2002, 2003 and 2004 are specified in Table 3-5.

Table 3-5. Quantities of electricity and heat generated at cogeneration plants and fuel consumption

Year	Electricity production, GWh	Heat production, GWh	Fuel consumption			
			Total, GWh	Natural gas %	Fuel oil, %	Other types of oil* %
2004	3 214	5 627	12 441	79.2	8.3	12.5
2003	2 996	5 349	11 769	78.9	10.3	10.8
2002	2 327	3 714	9 532	66.1	16.8	17.3

* Waste heat, orimulsion, biogas

4 Methodology for calculation of electricity from cogeneration and efficiency of the cogeneration process

4.1 Methodology for calculation of electricity from cogeneration under Annex II of Directive 2004/8/EC

1. Electricity produced by cogeneration means that part of electricity the production of which resulted in the production of useful heat. The fuel burnt and the energy produced in peak or reserve boilers are not taken into account even if such boilers form part of a technological system of the cogeneration plant.

2. The total energy production efficiency of cogeneration units shall be established by dividing the useful energy generated during the combined power and heat production process per year by the amount of fuel consumed over the same period.

3. The amount of electricity from cogeneration shall be determined on the basis of the expected or actual volumes of production under normal conditions of operation of the unit. For micro-cogeneration units (up to 50 kW of electric capacity), the total generated amount of electricity shall be considered to be the amount of electricity from cogeneration and shall be calculated using the data on the technical certificate.

4. The total amount of electricity shall be considered to be electricity from cogeneration recorded at generator terminals (gross), provided that the following conditions are met:

   4.1 The total annual energy production efficiency of the cogeneration units listed below is at least 75%:

   a) backpressure steam turbines
   b) gas turbines with heat recovery
   c) internal combustion engines
   d) micro-turbines
   e) Stirling engines
   f) fuel cells

   4.2 The total annual energy production efficiency of the cogeneration units listed below is at least 80%:

   a) combined cycle gas turbines with heat recovery
   b) condensation steam turbine with intermediate steam extraction

5. When the total annual energy production efficiency of cogeneration units is below the abovesaid values respectively by unit type, the following formula shall be used to calculate electricity from cogeneration:

$$E_{CHP} = H_{CHP} * C$$

where $E_{CHP}(P_{CHP})$* is the amount of electricity from cogeneration,
$C(\sigma_{CHP})$ is the power-to-heat ratio,
H_{CHP} (q_{CHP}) is the amount of useful heat resulting from cogeneration calculated for this purpose as total heat production minus any heat produced in separate boilers or by live steam extraction from the steam generator before the turbine).

6. The calculation of electricity from cogeneration must be based on the actual power-to-heat ratio based on the annual production of power and useful heat.
7. The sequence of calculation of electricity from cogeneration for a period of one year:

7.1 Necessary actual data:

a) actual amount of useful heat produced by cogeneration units

q_{CHP} [MWH]

b) actual amount of electricity generated at cogeneration units (gross)

p [MWh]c

c) actual fuel consumption

f [MWh];

7.2 Determination of the type of cogeneration unit (according to paragraph 2)

7.3 Determination of the total efficiency of the cogeneration plant, η:

$$\eta = \frac{p + q_{CHP}}{f - f_{non-CHP,q}}$$

where $f_{non-CHP,q}$ means the amount of fuel consumed for heat production in non-cogeneration units.

7.4 If the total efficiency η • 75% or 80% (according to unit type), the total amount of electricity shall be deemed to result from cogeneration in accordance with paragraph 2 of this methodology.

7.5 If the total efficiency η • 75% or 80% (according to unit type), the amount of electricity that may be recognized as produced by cogeneration shall be recalculated in the following manner (except condensation steam turbines with intermediate steam extraction):

a) Calculation of electricity production efficiency $\eta_{non-CHP,p}$

$$\eta_{non-CHP,p} = \frac{p}{f - f_{non-CHP,q}}$$

b) Calculation of the power-to-heat ratio, C (σ_{CHP})

$$C = \sigma_{CHP} = \frac{\eta_{non-CHP,p}}{\eta_{CHP} - \eta_{non-CHP,p}}$$

where the total cogeneration unit efficiency (η_{CHP}) is equal to, respectively, 75% or 80% (according to the type of the unit).

c) Calculation of electricity from cogeneration

$$E_{CHP} = p_{CHP} = C * q_{CHP} \text{ [MWh]}$$

d) Fuel consumed to produce electricity by cogeneration:

$$f_{CHP} = \frac{p_{CHP} + q_{CHP}}{\eta_{CHP}}$$

8. If the total efficiency of condensation steam turbines with intermediate steam extraction is η • 80%, the amount of electricity that may be recognized as produced by cogeneration shall be recalculated in the following manner:

a) The electric capacity loss coefficient β_{CHP} is calculated. The electrical capacity loss coefficient may be measured or, if impossible, calculated**.

b) The efficiency of electricity production, $\eta_{non\text{-}CHP,p,}$ is calculated

$$\eta_{non-CHP,\,p} = \frac{p + \beta_{CHP} * q_{CHP}}{f - f_{non-CHP,\,q}}$$

c) The power-to-heat ratio, C (σ_{CHP}) is calculated:

$$C = \sigma_{CHP} = \frac{\eta_{non-CHP,\,p} - \beta_{CHP} * \eta_{CHP}}{\eta_{CHP} - \eta_{non-CHP,\,p}}$$

where the total cogeneration unit efficiency (η_{CHP}) equals 80% (according to unit type).

d) The amount of electricity from cogeneration is calculated:

$$E_{CHP} = p_{CHP} = C * q_{CHP} \text{ [MWh]};$$

e) The fuel consumed to produce electricity by cogeneration:

$$f_{CHP} = \frac{p_{CHP} + q_{CHP}}{\eta_{CHP}}$$

9. When the actual power-to-heat ratio of a cogeneration unit is unknown, it is recommended that calculation of electricity from cogeneration (especially as regards statistical targets) should use the set power-to-heat ratio values, provided that the calculated electricity from cogeneration is lower than or equal to the total electricity production by that unit.

Unit type	The set power-to-heat ratio, C
Combined cycle gas turbine with heat recovery	0.95
Backpressure steam turbine	0.45
Condensation steam turbine with intermediate gas extraction	0.45
Gas turbine with heat recovery	0.55
Internal combustion engine	0.75

10. If during the process of combined heat and power production part of the used fuel is returned in the form of chemicals and recycled, before calculating the total process efficiency the returned part of the fuel shall be subtracted from the amount of consumed fuel intended for combined power and heat.

*Note. The symbols are in line with those used in Directive 2004/8/EC; the symbols specified in parenthesis correspond to the market used in the *Manual for Determination of Combined Heat and Power (CWA 45547, September 2004).*

*** Note. The measuring methods are described in Manual for Determination of Combined Heat and Power (CWA 45547, September 2004)*

4.2 Methodology for determination of the efficiency of combined heat and power under Annex II of Directive 2004/8/EC

1. Determination of the efficiency of combined heat and power and primary energy savings (PES) shall use the values set in accordance with the expected or actual operation of the unit under normal conditions of use.
2. High-efficiency of combined heat and power must meet the following requirements:

   2.1 The amount of primary energy saved in the course of combined heat and power production in cogeneration units, calculated in accordance with the procedure described in paragraph 2.2, must amount to at least 10% of separate production of heat and power.

   2.2 Combined heat and power at low electric capacity (<1 MW) and micro (<50 kW) cogeneration plants is recognized as high-efficiency heat and power production in the case of any primary energy savings (PES>0).

   2.3 The procedure of calculating primary energy savings:

   The primary energy savings during combined heat and power shall be calculated using the following formula:

$$PES = \left(1 - \frac{1}{\frac{CHPH\eta}{refH\eta} + \frac{CHPE\eta}{refE\eta}} \right) * 100\%$$

where:

PES stands for primary energy savings (%);

CHP Hη ($h_{CHP,q}$)* is the heat efficiency of the cogeneration production defined as annual useful heat output divided by the fuel input used to produce the sum of useful heat output and electricity from cogeneration;

CHP Eη ($h_{CHP,p}$) is the electrical efficiency of the cogeneration production defined as annual electricity (gross) from cogeneration divided by the fuel input used to produce the sum of useful heat output and electricity from cogeneration. Where a cogeneration unit generates mechanical energy, the annual electricity from cogeneration may be increased by an additional element representing the amount of electricity which is equivalent to that of mechanical energy. This additional element will not create a right to issue guarantees of origin in accordance with Article 5.;

ref Hη ($h_{non\text{-}CHP,q,ref}$) is the efficiency reference value for a heat production unit;

ref Hη ($h_{non\text{-}CHP,p,ref}$) is the efficiency reference value for an electricity production unit, when only electricity is produced (condensation plant).

**Note. The symbols correspond to the ones used in Directive 2004/8/EC; the symbols specified in parenthesis correspond to the ones used in the Manual for Determination of Combined Heat and Power (CWA 45547, September 2004).*

2.4 Efficiency reference values for separate production of heat and electricity:

The established production efficiency reference values shall be based on the following principles:

a) The comparison between combined heat and power production and separate heat and power production shall be based on the principle that the same primary energy source, i.e. fuel, is used in both cases;

b) Each cogeneration unit shall be compared with the best available technologies for separate production of heat and electricity of the same year;

c) Efficiency reference values for cogeneration units older than 10 years of age shall be fixed on the reference values of units of 10 years of age;

d) Efficiency reference values for separate electricity production and heat production shall reflect the climatic difference between Member States.

e) And all other principles, such as losses in power lines, voltages etc.

EU-approved reference values for production efficiency:

5 Evaluation of the national high-efficiency cogeneration potential

5.1 Short guidelines for the evaluation of national potential

Presented below is the algorithm on the evaluation of the national potential for combined heat and power in line with EU recommendations.

<table>
<tr><td rowspan="7">Second adjustment to political objectives</td><td colspan="2">National policy objectives</td><td rowspan="7">First adjustment to political objectives</td></tr>
<tr><td>Demand/supply</td><td>Respective fuel</td></tr>
<tr><td colspan="2">Technical potential according to the heat market and respective cogeneration technologies</td></tr>
<tr><td colspan="2">Economically useful potential based on the economic and financial analysis</td></tr>
<tr><td colspan="2">Identification of barriers interfering with utilization of the economically useful potential</td></tr>
<tr><td colspan="2">Cogeneration strategy formulation (promotion schemes etc.)</td></tr>
<tr><td colspan="2">Report to the EU</td></tr>
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Fig. 5-1. Algorithm for the determination of the national high-efficiency cogeneration potential

National policy objectives

- Energy supply security;
- CO_2 emissions reduction;
- Energy production from renewable and domestic energy sources;
- Other environmental objectives;
- Fuel supply security.

The demand/supply structure

- Electricity sector overview;
- Electricity production model;
- Consumption of primary energy, i.e. fuel, in the energy sector;
- District heating market.

The respective types of fuel

- Fuel used in cogeneration plants; its availability.

Technical potential according to the heat demand market and the respective combined heat and power technologies

- Heat demand in the residential sector (district heating);
- Heat demand in the industrial sector unconnected to district heating (steam / heating water / mechanical energy);
- Cooling energy demand that may be satisfied using heat;
- The list of the respective technologies for combined heat and power which depend on the heat market.

Economically useful potential based on the economic and financial analysis

- Setting the economic and financial prices of fuel and electricity;
- Other economic/financial conditions;
- Economically justified potential.

Barrier identification

- Technical barriers;
- Financial barriers;
- Administrative barriers.

5.2 Overview on the national level

5.2.1 National policy objectives

Lithuania's national energy policy objectives, which are set out in the Lithuanian National Energy Strategy, were established with regard to the domestic as well as external factors. A major influence on the formulation of these objectives was the energy development directions selected by the EU and other developed countries: universal and open competition, an open energy market in every country and between countries, as well as increasingly strict environmental requirements.

The Lithuanian Energy Strategy sees the country's future energy as a constituent of advanced economy of a modern society, supplying energy, at economically justifiable prices based on real costs and performance, to all branches of economy in an environment-friendly way, creating favourable conditions for further progress of the country, integrated into both western and eastern energy systems and capable of competition in the open international market for energy. This means well-balanced energy sectors enabling further development of the society and economic growth.

Directly related to effective development of combined heat and power, the strategic objectives of the Lithuanian energy sector, are the following:

1) to ensure reliable and safe energy supply, while minimizing the costs and environmental pollution and improving the performance of the energy sector;
2) to liberalize the electricity and natural gas markets, opening up the market in accordance with the requirements laid down in EU Directives;
3) in accordance with the time limits agreed upon with the European Union, to launch a set of measures facilitating the implementation of EU environmental directives in the energy sector, and to enforce nuclear safety requirements;

4) during the next ten years, to integrate the Lithuanian energy systems into the European Union's energy systems;
5) to continue the expansion of regional collaboration and cooperation with the aim to create a single Baltic States' energy market within the next five years;
6) to continue the active policy for integration into the West and Central European electricity markets and to make sure the energy resource transit across the territory of Lithuania is regulated in compliance with the Energy Charter as well as EU legislation and practices;
7) to increase the efficiency of district heating systems;
8) to make sure that the share of energy produced by cogeneration in the total balance of electricity production amounts to at least 35% at the end of the period;
9) to raise the share of renewable energy resources in the total primary energy balance to 12% by 2010;
10) to enhance energy sector management by strengthening the institutions operating in the sector and to improve the knowledge and skills of their staff.

The goals set for the environmental sphere, which is closely linked with energy, are a major influence on the development of the Lithuanian energy sector. One of the main agreements reached by the international community, which has a direct relation to the current functioning of the energy sector and its further development, is the United Nations Framework Convention on Climate Change (UNFCCC), ratified by the Seimas of the Republic of Lithuania in 1995, which contains a provision on mandatory reduction of greenhouse gas emissions. With the adoption by the Seimas of the Republic of Lithuania of the Law on the Ratification of the Kyoto Protocol in 2002, the country undertook specific obligations: until 2008-2012 to reduce greenhouse gas emissions by 8% (the current regulation concerns only CO_2 emissions) compared to the reference year 1990. The Kyoto protocol came into full effect as of 15 February 2005, when Russia joined the group of countries that ratified it.

The Kyoto Protocol envisages three mechanisms that countries must use to discharge their obligations to reduce CO_2 formation and emission into the atmosphere: the mechanisms of joint implementation projects, emissions trading, and clean development.

In order to achieve the aforementioned objectives, the Government of the Republic of Lithuania approved the heat sector development areas in 2004. One of its provisions emphasizes the development of cogeneration plants to increase energy production efficiency and reduce environmental pollution.

Future plans include introduction of the green certificate trading system, which will ensure additional financial mechanisms to support energy production from renewables.

Development of high-efficiency combined heat and power in the country facilitates the achievement of both energy and environmental objectives:

1) Development of high-efficiency combined heat and power would allow a more productive utilization of the available potential for district heating (DH).
2) The use of high-efficiency combined heat and power would ensure optimum conversion of primary energy. Primary energy economy would enable CO_2 emission reduction, i.e. would contribute to the Kyoto objectives.

5.2.2 National trends

An economically effective potential for high-efficiency combined heat and power also depends on various national economic factors, such as GDP growth, general economic environment, demographic forecasts and industrial development.

According to the National Energy Strategy, approved in 2002, as well as the Energy Development Strategy, the country's economic development forecasts have three scenarios: the rapid economic growth scenario, the main scenario, and the slow economic development scenario. Bearing in mind the actual national economic growth over the last three years, the rapid economic growth scenario seems the most probable (7% GDP growth, compared to actual GDP growth of 6.8% in 2002, 10.6% growth in 2003, 6.9% growth in 2004 and 6.9% growth over the first nine months of 2005). Based on forecasts by the Ministry of Finance, the pace of GDP growth until 2008 is likely to remain quite rapid, at 6.3% on average per year.

The annual inflation prediction for the period until 2008 stands at 2.5%.

Energy demand forecasts

In 2004, the total domestic consumption of electricity amounted to 12.1 TWh, while the total production reached 19.3 TWh. The total heat consumption (production) amounted to 15.2 TWh. [24]

Figures 5-2 and 5-3 present the latest forecasts by the Lithuanian Energy Institute regarding growth in demand for electricity and heat until 2025 in respect of all three economic growth scenarios. The forecasts for the year 2020 put national demand for electricity at 15.5 TWh for the main scenario and at 17 TWh for the rapid economic growth scenario. The demand for heat will grow only insignificantly, as connection of new customers is compensated for by energy efficiency improvement measures: in 2020, the heat demand is estimated at 18 TWh for the main scenario and at 20 TWh for the rapid economic growth scenario [29].

Metai – Year

Faktiniai duomenys – Actual data

Greito augimo scenarijus – Rapid growth scenario

Pagrindinis scenarijus – Main scenario

L•to augimo scnenarijus – Slow growth scenario

Fig. 5-2. Electricity demand forecast

Metai – Year

Faktiniai duomenys – Actual data

Greito augimo scenarijus – Rapid growth scenario

Pagrindinis scenarius – Main scenario

L•to augimo scnenarijus – Slow growth scenario

Fig. 5-3. Heat demand forecast

The studies conducted by Kaunas University of Technology give forecasts for electricity production demand and instantaneous power until 2025 [30]. They concluded that, under the slow economic growth scenario, the electric energy and power requirements in Lithuania may reach 15.3 TWh and 2 900 MW in 2020, and 16.3 TWh and 3 024 MW in 2025; under the rapid economic growth scenario: 19.7 TWh and 3 730 MW in 2020 and 25.3 TWh and 4 694 MW in 2025; under the very rapid economic growth scenario: 22.1 TWh and 4 180 in 2020 and 25.9 TWh and 4 805 MW in 2025.

Table 5-1. Maximum required capacities of the energy system

Scenarios	Units	2000	2005	2010	2015	2020	2025

Slow: electricity demand	TWh	8.3	10.3	12.1	13.7	15.3	16.3
T_{max}	hrs.	4729	4898	5061	5168	5282	5390
P_{max}	MW	1755	2103	2391	2651	2897	3024
Rapid: electricity demand	TWh	8.3	10.8	13.2	16.2	19.7	25.3
T_{max}	hrs.	4729	4898	5061	5168	5282	5390
P_{max}	MW	1755	2205	2608	3135	3730	4694
Very rapid: electricity demand	TWh	8.3	11.5	14.8	18.5	22.1	25.9
T_{max}	hrs.	4729	1898	5061	5168	5282	5390
P_{max}	MW	1755	2348	2924	3580	4184	4805

5.3 Current energy supply and demand structure

5.3.1 General information

This chapter gives a short overview of the energy sector: the fuels used, an overview of the electricity sector and an overview of district heating.

Table 5.1 presents the main fuel and energy balance indicators. Table 5-2 illustrates the heat and electricity balances. [24]

Table 5-2. The main fuel and energy balance indicators, 2004

Primary energy consumption, ktoe Of which:	9 116.3
Natural gas	2 343
Coal and peat	182.2
Petroleum products (including orimulsion)	2 538.5
Nuclear energy and hydropower (including net electricity import)	3 355.8
Firewood and other renewables	696.8
Of them, in the energy sector, ktoe	4 054.4

Table 5-3. Power and heat balances, 2004

Net heat production, GWh Of which:	15 200.6
Thermal power plants	6 420
Boiler-houses	4 754
Electricity (electrode) boiler-houses	9.3
Ignalina NPP	549.9
Utilization units (Mažeiki• nafta, K•daini• Lifosa, Jonavos Achema and others)	3 242.4
Geothermal units	225
Losses in heat networks	2 226.9
Gross electricity production, GWh Of which:	19 274.3
Thermal power plants	3 228.6
Wind power stations	1.2

Ignalina NPP	15 101.6
Kruonis Pumped Storage Power Plant	522.5
Kaunas Hydroelectric Power Plant	359.0
Small hydroelectric power plants	61.5
Losses in power networks	1 273.4

5.3.2 Overview of district heating

At present, the centralized and the decentralized types of heating each account for 50% in the total heat production balance. The heating season lasts 6-7 months per year.

In 2004, 8 140 GWh of energy was supplied centrally. 5 706 of the said amount was used to satisfy the heating and hot water needs of households. The remaining part of heat (around 29%) was bought by budgetary institutions, businesses and industrial enterprises, as well as other consumers.

Gyventojai – Residents

Biudžetin•s organizacijos – Budgetary organizations

Verslo/pramon•s •mon•s – Business/industrial companies

Kiti vartotojai – Other consumers

Fig. 5-4 Heat consumption (final demand), 2004

The difficult financial situation of the population along with the financial problems faced by budgetary institutions are the reasons behind the still significant indebtedness for heat consumption in the district heating sector, although the number of consumers has been on the rise.

Bendras vartotoj• skai•ius - Total number of consumers

•siskolinusi• vartotoj• skai•ius – The number of indebted consumers

Fig 5-5. Heat consumer dynamics, 2001-2004

In the first half of 2005, the total number of consumers amounted to 584 225.

All in all, Lithuania has 44 heat supply companies. Over recent years, private participation in heat supply has been growing. At present, a 38.3% share in the district heating market is held by Dalkia, a French company, and a 59% share belongs to municipalities which control district heating companies, while the remaining share is held by other private companies. The Law on the Heat Sector stipulates that district heating networks may be owned by municipalities, while private suppliers may own up to 70% of heat production sources. Companies such as Dalkia have entered into long-term lease agreements with municipalities in order to operate a heat supply enterprise.

District heating enterprises must obtain licences to supply heat. Enterprises that supply more than 5 GWh of heat per year obtain heating licences from the Lithuanian National Control Commission for Prices and Energy. The licence is issued for an unlimited period of time. Licences authorising heat supply in a particular region are issued only to a single company.

District heating accounts for 2.5% of the gross domestic product (roughly LTL 1 billion). Currently, more than 60 heat supply enterprises operate on the market (they supply over 5GWh of heat per year). The table below specifies the main indicators of the district heating sector.

Table 5-4. Main indicators of the district heating sector

Indicators	2001	2002	2003	2004
Heat produced , GWh	10700	10632	10440	10300
Heat sold, GWh	8166	8244	8309	8140
Revenues, million LTL	938	960	957	924,4
Costs of production, transmission and sales, million LTL	924	926	898	874,4
Average fuel unit price, LTL/toe	465.5	450.9	451.1	434.0
Gross profit, million LTL	13.3	34.4	58.4	50.0
Average price, cents/kWh	11.44	11.65	11.51	11.35
Average costs cents/kWh	11.35	11.23	10.81	10.74

In the CH system, 40% of all costs are relatively constant, as they must be borne irrespective of the amount of heat consumed. For that reason, the amount of heat sold is a crucial factor in determining the price of heat. Prior to 2000, heat production and sales were declining as a result of the economic situation in the country:

- bankruptcies of industrial enterprises,
- transition to decentralized gas heating,
- decline in production and living standards and subsequent decrease in heat consumption,
- introduction of more effective production and saving instruments etc.

Due to the decline in heat sales, the prices of heat had to be increased in order to ensure the viability of district heating companies. However, over recent years heat supply volumes have stabilized, thus creating the preconditions for the economic stability of the CH sector.

Pateikta • tinkl•, TWh – Supplied to the network, TWh

Pateikta vartotojams, TWh – Supplied to consumers, TWh

Fig. 5-6. Heat balance (1996-2004)

The main heat transmission networks are 30-40 years old and nearing the end of their service life. As a result of the decentralization of loss-making consumers and the renovation and expansion of the networks, district heating enterprises have achieved significant cuts in technological transmission losses. In 2004, technological losses amounted to 21% (compared to the amount of generated heat).

In the current total heat production balance, heat produced at thermal power plants accounts for more than 50%. The share of thermal power plants in total electricity production is currently 17%.

Elektros ir šilumos dalis pagaminta šilumin•se elektrin•se – Share of electricity and heat produced by thermal power plants

Elektros dalis pagaminta šilumin•se elektrin•se – Share of electricity produced by thermal power plants

Šilumos dalis pagaminta šilumin•se elektrin•se – Share of heat produced by thermal power plants

Fig. 5-7. The amount of electricity supplied by thermal power plants to the network

The prices (tariffs) of district heat are regulated by the National Commission for Prices and Energy. Long-term basic prices are established for a period of at least three but not more than five years. Prices are fixed taking into consideration the costs of the services of heat production, transmission and, in certain cases, sales. Therefore, changes in production costs, such as a rise in fuel prices, may have an impact on consumer prices.

District heating companies may conclude contracts with the so-called competitive consumers, where the price may be established by mutual agreement. In any event, the price must cover the production and transmission costs and must be approved by the National Commission for Prices and Energy.

The average price of heat is consistently declining: in 2002, it peaked at LTL 116.5/MWh (excl. VAT); in the first half of 2005, the average price of heat was LTL 111.10/MWh (excl. VAT).

As already mentioned above, a major influence on the profitability of district heating enterprises is the prices of fuel, as these costs represent roughly 46% of the cost of the heat.

An analysis of the fuel cost dynamics in the 1996-2004 period reveals an upward tendency in the share of renewables, especially biofuels, in the total fuel structure.

Gamtin•s dujos – Natural gas

Mazutas – Fuel oil

Atsinaujinantys energijos ištekliai – Renewable energy sources

Kitas kuras – Other types of fuel

Fig. 5-8. Fuel cost dynamics, 1997-2004

According to estimates, heat production from domestic, renewable and waste resources in the total heat balance will account for 17% in 2010 and 23% in 2020.

5.3.3 Electricity production structure

The installed (total) capacity of Lithuania's power plants in 2004 amounted to 6 127 MW. Following the closure of Unit 1 of the nuclear power plant, the installed capacity shrank to 5 000 MW. Cogeneration plants account for 52%, the nuclear power plant for 27%, and hydroelectric power plants for 19% of this amount.

Lithuania's main power stations are the Ignalina Nuclear Power Plant (INPP) with an installed capacity of 1 300 MW in 2005 (Unit 1 of the INPP was closed at the end of 2004), the Lietuvos Elektrin• power plant (1 800 MW), Kruonis Pumped Storage Power Plant (800 MW), and Kaunas Hydroelectric Power Plant (100 MW). Apart from these power stations, Lithuania also has three major cogeneration plants - in Vilnius, Kaunas and Mažeikiai - as well as a number of small cogeneration stations set up at industrial or heat network companies, as well as some wind and biomass power stations. The installed capacity of cogeneration plants amounts to 732.8 MW. Lietuvos Elektrin• and the cogeneration plants, except the Mažeikiai cogeneration plant, may use both fuel oil and gas as fuel (and orimulsion in the case of Lietuvos Elektrin•).

According to the data of the Lithuanian Ministry of the Economy, the maximum capacity demand in 2004 totalled 1 952 MW [23]. Taking into account the 1 300 MW capacity reserve, the surplus capacity in 2005 totalled 1 575 MW without the export requirement.

Table 5-5. Lithuanian power plants, their capacities and electricity supplied to the network in 2004 [23,24]

Power plants	Installed/available capacity, MW	Average annual power plant utilisation rate	Electricity supplied to network, million kWh

Ignalina NPP	2 600 / 2 366	0.94	15 101.6
Thermal power plants:	2 532.8 / 2 424.0		
Lietuvos Elektrin• power plant	1 800 / 1 732	0.08	745.4
Mažeikiai Power Plant	160/148	0.15	142.5
Vilnius Power Plant TE-3 TE-2	384 / 367 - 360 / 343 - 24/24	0.47; 0.72	1210.7
Kaunas Power Plant	170/ 161	0.66	688.6
Kauno energija (Petraši•nai Power Plant)	8/7	0.01	0.7
Klaip•dos energija	10.8/9	0.38	33.8
Hydroelectric power plants	920.5 / 850		
Kaunas Hydroelectric Power Plant	100.8/90		359
Kruonis Pumped Storage Power Plant	800 / 760	0.45	522.5
Small hydroelectric power plants	19.7		61.5
Industrial and other power plants, of which	74.1 /46.0		346.41
Biomass	2.9		61.6*
Wind	0.79		
Total:	6 127 / 5 686		19 274.3

* includes small hydroelectric power plants

In Lithuania, the installed surplus amount of electric capacity has resulted in a rather small utilisation rate at some of Lithuania's power plants, especially the Lietuvos Elektrin•. The electric utilization rate of the cogeneration cycle is comparatively high during the heating season. The high utilization rate of the Ignalina Nuclear Power Plant owes to the volume of electricity export.

19.3 TWh of electricity was produced in Lithuania in 2004. The same year, AB Lietuvos energija exported 7.3 TWh of electricity. 2.6 TWh went to Belarus, 3.9 TWh to Russia, 0.6 TWh to Latvia, 0.2 TWh to Poland and 0.05 TWh to Estonia.

According to the latest data of the Ministry of the Economy of the Republic of Lithuania, 10.8 TWh of electricity was generated in the first nine months of 2005 (71% by Ignalina NPP, 23% by thermal power plants, and 6% by hydroelectric power plants and the pumped storage power plant), which is 26% less than in the first nine months of 2004. The reduced energy production resulted from a decline in export. During the first nine months of this year, the electricity export amounted to 2.97 TWh, showing a 2 TWh decrease year on year. The export has declined due to the repairs of Unit 2 of the INPP. Consumer costs during this period edged up by 5%. The bulk of electricity was consumed in industry (32%) and households (26%).

The future plans include building a 25 MW cogeneration plant in Panev•žys as well as additional 100 MW electricity production capacities using renewable energy sources, primarily wind energy.

Table 5-3 specifies the planned energy system capacity balances for 2005-2007.

Table 5-6. Planned capacity balances of the Lithuanian energy system at the time of maximum demand [23]

	2005 MW	2006 MW	2007 MW
Installed/available capacity of power plants (excluding wind, biomass and small power stations)	4503*	4503	4526
Maximum required capacity of the system at maximum demand growth	1920	2010	2090
Export	-500	-500	-500
Mandatory long-term reserve	1300	1300	1300

Capacity balance (surplus)	783	693	636

* INPP capacity: 1 300 MW (Unit 1 closed)

In the specified period, the available electricity production capacities fully meet the requirements of Lithuanian consumers and enable electricity export. Lithuania has retained a surplus of electricity production capacities, therefore no major additional capacities are envisaged.

Power transmission and distribution networks in principle satisfy the current electricity system requirements. However, their age requires investments to sustain the current level of power networks, to meet the increasingly high demands concerning energy supply reliability and to create a single electricity market for the three Baltic States.

The electricity market today

DIDMENIN• RINKA	**WHOLESALE MARKET**
ELEKTROS ENERGIJOS GAMYBA (IAE, LE, VE, KTE, kt)	**ELECTRICITY production (INPP, LIETUVOS ELEKTRINE, VILNIUS POWER PLANT, KAUNAS HEAT AND POWER PLANT etc.)**
RINKOS OPERATORIUS (AB "LIETUVOS ENERGIJA")	**MARKET OPERATOR (AB LIETUVOS ENERGIJA)**
KVOTOS VIEŠIEJI INTERESAI	**QUOTA PUBLIC INTEREST**
AUKCIONAS	**AUCTION**
DVIŠALIAI KONTRAKTAI	**BILATERAL CONTRACTS**
BALANSAVIMO ENERGIJA	**BALANCING POWER**
NEPRIKLAUSOMAS TIEK• JAS	**INDEPENDENT SUPPLIER**
SKIRSTOM• J• TINKL• •MON•	**DISTRIBUTION NETWORK ENTERPRISE**
PERSIUNTIMO PASLAUGA	**TRANSMISSION SERVICE**
VISUOMENINIS TEIK• JAS	**PUBLIC SUPPLIER**
LAISVIEJI VARTOTOJAI, PASIRINK• NEPRIKLAUSOM• TIEK• J•	**ELIGIBLE CONSUMERS HAVING SELECTED AN INDEPENDENT SUPPLIER**
KITI VARTOTOJAI	**OTHER CONSUMERS**
MAŽMENIN• RINKA	**RETAIL MARKET**

Figure 5-9. Structure of the electricity market today

The electricity sector consists of two major activities: electricity production and electricity transmission from producer to consumer.

Electricity production is carried out by power plants that sell their production in the common wholesale market of suppliers and producers. Production and supply operate under competitive conditions, and electricity transmission naturally is a monopolistic activity.

The produced electric energy is sold based on bilateral contracts and public interests established by quotas, and by auction.

Despite the fact that the market in electricity has existed for already three years, the situation has not actually changed much during that period. The Ignalina Nuclear Power Plant has retained its position as the main producer of electricity. Since the production costs of other power plants are higher, they can aspire after only an insignificant market share. The consumption by consumers who have chosen an independent supplier accounts for merely 15% of the total sales in the market [23]. All of them are connected to a high voltage network, which shows that the consumers that are connected to a medium and low voltage network will find it cheaper to purchase power form the public supplier.

Foreign electricity market

Historically Lithuania was part of the Soviet energy system. Consequently, the Lithuanian energy system is connected with Latvia, Belarus and Russia (Kaliningrad), but is not sufficiently linked with the European Union. The capacity of the existing connecting lines is specified in the table below.

Table 5-7. Lithuania\s connecting lines with neighbouring countries (Source: Eurelectric, European Interconnection)

Lithuania-Latvia		Voltage, kV	Capacity, MW
Klaip•da	Grobinia	330	789
Šiauliai	Jelgava	330	789
Panev•žys	Pliavine	330	789
Ignalina NPP	Liksna	330	943
Lithuania-Belarus			
Ignalina NPP	Polosk	330	1 097
Ignalina NPP	Belaruskaya	330	1 143
Ignalina NPP	Smorogon	330	943
Vilnius	Molodechno	330	943
Alytus	Grodno	330	789
Lithuania - Kaliningrad (Russian Federation)			
Kruonis	Sovetsk	330	1 143
Jurbarkas	Sovetsk	330	572
Klaip•da	Sovetsk	330	572

At present, Lithuania is looking for ways to interconnect the Lithuanian and the EU electricity systems. The projects listed below are being developed or already being implemented:

- A 400 kV double circuit line connecting the Polish town of E•k and the Lithuanian town of Alytus as well as a 600 MW converter on the Lithuanian side should become the main link with the EU. The Lithuanian and Polish authorities are looking for ways of using EU funding for this project. The EU has recognized it as a priority project; however, the specific dates and project funding have not been approved so far. For these reasons, this line is not likely to be completed before 2009.
- The Lithuanian transmission network and market operator Lietuvos Energija is involved in the construction of a 350 MW underwater power transmission line between Estonia and Finland. Lietuvos Energija will hold a 25% stake in the company that will manage the transmission line. However, as a low-capacity and rather remote line, it is not likely to significantly improve the import or export opportunities for Lithuanian producers. The line should be completed in 2006 and Lithuania plans to export at least 560 000 MW of electricity over this line per year.

A feasibility study on the connection of the Lithuanian and Swedish energy systems by an underwater power line has been completed. This line would also ensure a link with Poland, since the Polish and Swedish power networks are connected at the place where the construction of the new line is envisaged. However, the possibility of implementing this project is yet uncertain, and even if it is implemented, this will not happen before 2009.

All of Lithuania's neighbours, including Latvia, Belarus and Kaliningrad are short of electricity production capacities and are electricity importers. Thus, an increase in the electricity import by 2009, when the Ignalina NPP is fully decommissioned, should not be expected. There are no plans for the near future to build any major power stations in the region, except for a 450 MW thermal power plant in Kaliningrad, which is scheduled to be launched in 2005.

The Lithuanian and EU energy systems are not sufficiently interconnected to allow integration into the EU market. The required connecting lines could be installed no sooner than 2009.

The possibility of importing electricity in the future will also depend on the completion of the projects for the Lithuanian and EU power network connection as well as on the electricity prices in the region. Poland, a potential electricity trade partner in the future, is also implementing the EU directives governing market liberalization, which promises changes on this market.

Electricity sector regulation

The main principles governing electricity production, transmission, distribution and supply are laid down in the Law on Electricity. The implementation of this law as well as implementation of other legislative acts necessary to implement the said law is supervised by the National Commission for Prices and Energy.

Energy sector regulation is carried out by means of price regulation, issuance of licences, certificates and permits for activities in the energy sector, State control of energy companies, requirements for energy efficiency of units, requirements for energy metering etc.

Electricity prices are contractual and regulated, i.e. the price caps are fixed. In the process of fixing State-regulated prices, the necessary costs of energy resource extraction, energy production, purchase, transmission, distribution and supply, also energy sector development and energy efficiency, use of domestic and renewable energy sources and fulfilment of public service obligations must be envisaged and the profit margin must be set.

The public interest services include:

1. Combined heat and power (electricity generated at cogeneration plants).
2. Energy produced using renewable energy sources or waste incineration.
3. The necessary nuclear energy costs to ensure occupation safety, necessary to store or burry waste.
4. Electricity production necessary to ensure the necessary electricity system reserve (Lietuvos Elektrin•).

5.4 Fuels and prices

In order to ensure objectivity of assessments on a scale of national interests, social-economic prices of resources are used in the calculations.

Economic prices are prices used in economic assessments. They do not coincide with market prices and are also referred to as "shadow" or "estimated" prices, as they do not exist in reality. Economic prices are "pure" costs on the national level in the sense that they do not contain any taxes, customs duties, subsidies or other payments that are not related to the purchase or sale of real economic resources. The aim of economic prices is to evaluate national economic resources at international market prices. Therefore, project costs are evaluated in the context of both national as well as international economy.

Conversion from commercial (financial) to economic prices is carried out using coefficients that are set taking into consideration the fuel import price, the use of domestic workforce, paid taxes as well as profit. The coefficient applicable to investments is equal to 1, i.e. the whole commercial price is transferred to the economic price, while the coefficient of 0.5 is applied to the costs of wages, which means that 50% of gross costs of wages consist of personal income and social insurance taxes and avoided public expenditure on job creation; the coefficient for materials is 1.0; for fuel (transportation) – 0.4, i.e. the excise tax and the VAT account for 60%.

The main fuels now used for energy production are natural gas, fuel oil and biomass. Therefore, the forecasting of this fuel price decrease is important.

Trends in fossil fuel prices, key factors in determining such trends, and forecasts

The fossil fuel market and its change trends are undoubtedly one of the reflections of the developments in the global macroeconomics, international politics and social welfare. Having practically no (small amounts) of its own fossil fuel resources, Lithuania relies heavily on other countries and their internal processes. An analysis of fossil fuel ("Brent" oil) price decline over the last 15 years shows that in 1990, following the start of the first Gulf War, the oil prices began growing after previous decreases at the end of the ninth decade and reached USD 24 per barrel. During the 1991 military operation in the Middle East, oil prices on the markets were particularly unstable and started decreasing as the Gulf War ended. The trends of the Brent oil prices on the London International Exchange are illustrated in fig. 5-10 (the dotted line was obtained by linear approximation of the values of these prices) [1]

JAV dol./bar – USD/barrel

metai – year

*Average price during January-September 2005

Fig. 5-10. Brent oil prices on the London International Petroleum Exchange

In 1993, due to the excess oil production by OPEC countries and larger oil extraction volumes in the North Sea and lower oil demand, oil prices on the market kept declining: the average price in 2000 totalled around USD 24 per barrel, compared to USD 18 in 1993. However, due to the volatile political situation in the oil extracting countries and especially cold winters in the USA and Europe in 1994-1995, the oil prices went up again. A marked decline in the oil prices from 1996 to 1998 resulted from excessive supply and smaller oil demands in the wake of the economic crisis in Asian countries. After a reduction of oil supply by OPEC countries in 1999 and simultaneous increase in its demand, along with other economic and political factors, oil prices surged again. From January 1999 to September 2000, the oil price rocketed nearly threefold, from USD 12 a barrel to USD 34 a barrel [2]. The average oil price in 2000 was the highest over the last 17 years. In 2001, oil prices significantly decrease as a result of lower demand for oil caused by an economic downturn in the USA as well as overproduction by OPEC countries. Oil prices plummeted following the terrorist attack in the USA on 11 September 2001. After OPEC reduced oil extraction in 2002, also in response to unrest in Venezuela and growing tensions in the Middle East, oil prices increased again. In 2003-2004, changes in the oil prices were preconditioned by the continuing unrest in Venezuela, the start of the military intervention in Iraq and OPEC oil extraction restriction as well as limited oil reserves. The average oil price over the said period went up from USD 29 to USD 38 a barrel. Having begun in 2004, the surge in oil prices continued in 2005. It owed to political instability in oil extracting countries, consequences of natural disasters, a decline in the US dollar (the main currency in the oil market) exchange rate and growing global demand for oil. In the third quarter of 2005, the oil price on the markets jumped to nearly USD 70 per barrel. The average oil price in the first three quarters of 2005 stood at approximately USD 55 per barrel.

Forecasting fuel prices necessary for the development of energy system development or modernization plans is a difficult task due to the abundance of factors that may influence prices. Figure 5-11 presents the oil price forecasts by the International Energy Agency, one of the most reputed world energy organizations, for different periods and compares them with the actual prices [3].

JAV dol/br – USD/barrel

Faktas – Fact

metai – year

Fig. 5-11. Changes in IEA world market oil price forecasts depending on the forecasting year

Fig. 5-12 illustrates world oil prices forecasts for 2005 by several other organizations: AEO (Annual Energy Overview), Deutsche Bank, A.G. (DB), Energy Ventures Analysis, Incorporated (EVA) as well as by IEA [2].

JAV dol/br – USD/barrel

metai – year

AEO2005 (bazinis) – AEO2005 (basic)

AEO2005 (aukštos naftos kainos B) - AEO2005 (high oil prices B)

IEA (bazinis scenarijus) – IEA (basic scenario)

EVA – EVA

AEO2005 (aukštos naftos kainos A) - AEO2005 (high oil prices A)

AEO2005 (žemos naftos kainos) - AEO2005 (low oil prices)

DB - DB

Fig. 5-12. Oil price change forecasts for 2005 by different organizations

As we can see in figures 5-11 and 5-12, the accuracy of oil price forecasts depends not only on the assumptions used by their authors or the level of information available to them, but also on the year when the forecasts were made. When making long-term oil price change forecasts, a number of factors are taken into account: worldwide oil resources, extraction volumes, recycling capacities, and the envisaged technical and economic progress of supply and consumption systems. Nevertheless, actual oil prices differ markedly from the forecasts due to unforeseen political, natural or and other factors.

This study does not aim to maximise the accuracy of oil price forecasts and therefore the analysis of the changes in the prices of the most popular fossil fuels, such as natural gas, fuel oil and wood, relied on the forecasts made and used in other studies, taking into account not only the possible "macro" factors, but also the peculiarities of Lithuania. Summarization of the trends of the changes in the fossil fuel prices relied on the actual data of oil prices on the Lithuanian market (collected from district heating enterprises) as declared by the National Control Commission for Prices and Energy (VKEKK) as well as on the fossil fuel import or extraction prices and change prognoses used by the Lithuanian Energy Institute (LEI) [5, 6]. The summarized data, which will be used in the economic evaluation of the combined heat and power potential, are presented in figure 5-13.

faktin•s kainos – actual prices

prognozuojamos kainos – price forecasts

Eur/tne – EUR/toe

metai – year

gamtin•s dujos – natural gas

mazutas – fuel oil

mediena - wood

Fig. 5-13. Actual fossil fuel prices for Lithuanian final customers in 2001-2005 and change forecasts

A comparison of the fuel import and extraction prices as well as fuel prices in Lithuanian DH enterprises reveals that the average fuel transmission and distribution costs (the difference between the price paid by the consumer and the fuel import or extraction price) during the said period were the following: natural gas –

LTL 20.9/toe, fuel oil – LTL 22.0/toe, and wood – LTL 28.2/toe. Taking into account these additional costs as well as the economic fuel price forecasts used by LEI, predictions of fuel prices for customers can be made. A leap in natural gas prices, up to EUR 183.1/toe (LTL 569/thou nm^3), is anticipated as of 1 January 2006. During the subsequent period until 2025, the prices of natural gas are expected to rise at the speed of 1% per year, reaching EUR 198.6/toe (LTL 617/thou nm^3), The price of fuel oil with high sulphur content (>1% S), which increased over the recent years as a result of a hike in the oil price, should go down to EUR 145/toe (LTL 477/t). During the following period until 2025, it is expected to grow at a pace similar to that of natural gas, roughly 1% per year. In such a case, the price of fuel oil with high sulphur content is likely to reach around EUR 161/toe (LTL 528/t). It is even more challenging to predict the price of fuel oil with low sulphur content, as the possibilities of producing and importing it are unknown. Yet, the price of this type of fuel oil is likely to be 20-50% above the price of fuel oil with high sulphur content [10].

The growth of wood fuel prices, which was very rapid in the 2003-2005 period, is expected to slow down. Until 2025, the price of this type of fuel should grow by an average of 1.4% per year. The price of wood fuel, which stood at EUR 98.2/toe (LTL 338/toe) in Q1-Q3 2005, is expected to rise to EUR 126.5/toe (LTL 437/toe) by 2025.

Renewable energy sources (RES)

The potential for using renewable energy sources (RES) in combined heat and power directly depends on the energy qualities of an individual fuel, on the extraction conditions as well as on the possibilities for the organized supply of such fuel. The market for biomass fuel (wood, straw) is rapidly developing in Lithuania and therefore the issue of ensuring the necessary amount of resources is becoming increasingly important. Other renewable energy sources, such as landfill gas, wastewater treatment plant gas or biogas, in spite of the favourable energy and aggregation characteristics, do not satisfy the extraction and supply requirements. The use of such fuels in every specific case is an individual project interconnecting the aspects of several areas (waste management, wastewater treatment etc), including the aspects of energy.

Wood fuel

The resources of wood fuel usable as a source of energy may be divided into three groups:

1) Waste from the timber processing industry.
2) Felling waste
3) Cultivation of fast growing plants.

Due to its high energy value, waste from the timber processing industry enjoys huge demand on the market. However, tightening competition will force companies to look for more productive manufacturing methods, i.e. to apply the waste-free production cycle. It is assumed that the use of wood fuel in energy will consistently decline.

Utilization of felling waste in fuel production is not well-developed in Lithuania so far. Nevertheless, in view of the constant growth of the demand for biofuel in both the Lithuanian and foreign markets, the use of these resources will also have to be optimized. The annual amount of waste forming in harvest sites totals around 2.4 million m^3 [32]. Without significant damage to the forest environment, only up to a third of this amount can be taken, which means that annual potential of felling waste recycling into biofuel amounts to 0.8 million m^3. The preliminary estimate of logging costs relies on actual market prices as well as on the project *Development of Wood Use for Fuel Purposes in Lithuania*, carried out in 2000 by the Rokiškis State Forest Enterprise (supervised by the Department of Forests and Protected Areas under the Ministry of the Environment of the Republic of Lithuania) in cooperation with the Swedish National Forestry Board. The project identified the costs of preparing wood fuel, namely chips, in forest cuttings. They are presented in table 5-8.

Table 5-8. Commercial prices and the structure of economic-social prices of wood waste preparation in harvest sites

Cost component	Relative size of the component of commercial cost		Economic-social price of wood waste
Wood price at intermediate warehouses	77%	LTL 44.73 solid m^3	LTL 36.26 solid m^3
Wood loading/unloading	8%	LTL 4.90 solid m^3	LTL 4.90 solid m^3
Wood fuel transportation to boiler house[1]	5%	LTL 2.80 solid m^3	LTL 1.90 solid m^3
Profit margin	10%	LTL 5.84 solid m^3	LTL 5.84 solid m^3
Total	100%	LTL 58.27 solid m^3	LTL 48.90 solid m^3

The price estimate presented in Table 5-8 refers to chip preparation in young stand cuttings.

Logging from short life-cycle plants is a novelty in Lithuania [32]. In addition to the 70 ha planted this year, another 20 ha are planned next year. The common osier plantation is expected to expand up to 50 000 ha over the next 10 years. Determining the costs of producing this type of biofuel, taking into consideration the State subsidies it receives as well as the lack of actual producers, is a difficult task. Therefore, it is assumed that the cost of biofuel from short life-cycle plants should not be above the current market price. The actual wood waste market price amounts to LTL 50-70 per solid cubic metre.

According to the forecasts, the annual growth of the economic price of wood fuel totals approximately 1.4%.

Straw

Currently, the commercial price of straw in Lithuania ranges from LTL 30 to 90 per tonne. The average price totals LTL 60 per tonne. 12% of the total straw output can be used for biofuel purposes, yet so far only around 1% of the total amount of straw has been used for energy needs [33]. The approximate calorific value is 15 GJ/t at 10-20% humidity.

The table below specifies the economic and financial price of straw. The evaluation of labour and transportation costs relied on the information on the straw use market of Denmark (www.ekostrategija.lt), workforce costs etc.

Table 5-9. Economic and financial price of straw

Cost component	Relative size of the component of commercial cost		Economic-social price of straw
Straw packaging, loading/unloading	5%	LTL 3/t	LTL1.5/t
Transport	70%	LTL 42/t	LTL31.5/t
Other	25%	LTL 15/t	LTL12/t
Total	100%	LTL 60/t	LTL 45/t

Since the straw market potential is sufficiently high, the increase in the price of straw fuel is likely to depend on changes in the labour and transportation costs. An annual average growth of 0.9% is predicted for the price of straw [3].

Landfill gas

Due to both its aggregate form as well as environmental benefits (a renewable source of energy) landfill gas is a favourable fuel in terms of energy production. In order to ensure a regular landfill gas extraction debit (which changes in the course of use), it is necessary to apply a consistent landfill development strategy. The

[1] The estimate assumes that wood waste fuel is transported by a 85 m^3 chip truck with a trailer the maximum distance of 60 km from the place of intermediate warehousing.

use of landfill gas in cogeneration often becomes hardly possible due to the absence of useful heat demand, i.e. concentrated consumers of heat are too remote from the place of extraction of landfill gas.

Wastewater treatment plant gas

Wastewater treatment plant gas is a suitable fuel for cogeneration. However, given the local dimension of production of this gas, its use is limited.

Household waste

Currently, the use of household waste for combined heat and power in Lithuania is in the research stage. It would be unreasonable to identify the likely potential as well as the preliminary price of this fuel when no functioning system exists.

5.5 Cogeneration plant technologies for different heat market sectors

A large number of energy systems transforming primary energy into heat as well as electric energy exist in the world. Directive 2004/8/EC promoting combined production of heat and power in the domestic markets alone identifies 10 technologies capable of producing electricity along with heat.

This chapter introduces an analysis of the costs of construction and operation of the most common technologies, such as internal combustion engines, steam or gas turbines, and combined cycle. This analysis will serve as a basis for economic evaluation of the potential of combined heat and power.

5.5.1 The costs of setting up cogeneration plants

The total costs necessary for project implementation consist of the costs of equipment acquisition, installation, project development and implementation.

Equipment acquisition costs

They include the costs of equipment acquisition, transportation and relevant taxes, which to a large extent depend on a particular set of equipment as well as its technical characteristics. The following main components of cogeneration plant modules as well as the technical parameters describing them are identified:

- The primary source of energy (heat engine) and electricity generator. The main technical characteristics include parameters such as heat engine type, electrical (mechanical and heat capacity, type of fuel used, alternative fuel options etc;
- Heat abstraction and recovery installations (by air, steam or heating water; parameters of input flow: pressure, temperature);
- Additional heat production sources (fuel used, necessary additional capacity). Result: an opportunity to produce heat with higher energy potential or to cover peak demand for heat;
- A system of combustion products discharged into the environment (the temperature of discharged products, installations for emission reduction/monitoring);
- Fuel supply system (warehousing premises for solid fuel, a compressor for natural gas if the pressure of natural gas needs to be increased, containers for other (reserve) types of fuel, connection to the fuel supply line, fuel metering etc.);
- Control penal (the desired automation level – synchronization with the network, capacity distribution among modules etc);
- Connection to the power transmission networks (connection line, metering and protection instruments);

- A pipeline ensuring the supply or circulation of water, steam and compressed air (if necessary);
- Systems for ventilation and air supply for combustion (air ducts, filters, noise reduction systems);
- Additional equipment (water preparation installations, accumulation reservoirs etc);
- Equipment transportation, import and customs duties.

Installation costs consist of:

- Costs incurred in obtaining construction permits;
- Land acquisition and preparation work;
- Necessary premises construction work;
- Equipment installation and connection to external network costs;
- Preparation of required documentation.

When a cogeneration plant unit is placed at an already used boiler-house, some of the mentioned components of costs shall not be included into the installation costs.

Project development and implementation costs

They include an analysis of possible alternatives with a technical-economic substantiation, environmental studies, technical design, organization and management work as well as consulting and personnel training. Normally, this component of costs amounts to 15-30% of the main price of equipment and installation work [11; 12].

It should be noted that, depending on the type of concluded contracts, the costs of design preparation and implementation may also include the component for unforeseen costs (related to higher than expected Emergencies interest on loans, project insurance and other costs). In the main preliminary project stage, unforeseen cases may account for 15-20% of capital expenditure, while in the final stage of a project this share may be up to 5%.

The basic breakdown of total costs by different components is illustrated in figure 5-14 [11].

Kogeneracinis ir šilumos atgavimo •renginiai – Cogeneration and heat recovery installations

Papildomi •renginiai – Additional equipment

Instaliavimo ir paleidimo darbai – Installation and launching work

Projektavimo išlaidos – Design costs

Apr•pinimas •renginiais, kontrol• ir prieži•ra – Provision of equipment; control and supervision

Prisijungimas prie išorini• tinkl• – Connection to external networks

Paruošiamieji darbai (žem•, pastatai, keliai) – Preparatory work (land, buildings, roads)

Fig. 5-14 Breakdown of investments in a low-capacity cogeneration plant unit

As we see, the total project cost may depend on several factors. Summarized costs are used for preliminary project evaluation in the pre-project research stage. The exact amount of investment shall be established only after a detailed technical design is ready and the relevant equipment is selected.

Cogeneration plants with gas internal combustion engines

The module of the main electricity production unit consists of an internal combustion engine connected to an electricity generator. The set of a low-capacity Otto cycle internal combustion engine also comprises a fuel supply system and an integrated heat utilization (abstraction) system, electric pumps, a control panel with a launch system and the main control panel for connection to the electricity system.

The relative price per capacity unit of high capacity (> 1MWel) internal combustion engines as well as of those characterised by slow axle revolution may even increase as the capacity increases, while the modules of lower-capacity internal combustion engines require lower relative investments. This owes to the fact that low-capacity engines of this type are a product of mass production, often carried out together with the manufacturing of automobile or truck engines.

The price of the main module of an internal combustion engine, bearing in mind the requirement for additional equipment (depending on the peculiarities of specific electricity and heat consumers, the environmental requirements, the necessity of connection to external power networks as well as other factors), represents the total costs of equipment. The latter, together with the envisaged design, installation, project management and additional material costs represent the total project investments.

The final price of a set of auxiliary equipment and installation work may amount to 50-100% of the price of the main unit of electricity production, the module [12]. Based on data from various sources, the amounts of total relative investments in cogeneration plants with gas internal combustion engines are presented in figure 5-15.

Faktiniai – Actual

Figure 5-15. Total relative project costs of cogeneration plants with internal combustion engines (actual data based on projects carried out by UAB Manfula).

As we see, the costs of investments into internal combustion engines of different capacities slightly differ depending on the existing market circumstances, the requirements for the technical and environmental parameters of power plants as well as other factors. On the basis of the actual economic indicators of projects conducted in Lithuania, the estimate of investment costs in the country relies on the data falling within the economic indicator limits recommended in the references [13, 15].

As mentioned above, the price of the main module of electricity production (heat engine and electricity generator) rises with an increase in the installed electrical capacity. However, due to additional costs of heat energy utilization equipment, the electrical part, connection to external power networks and other costs, in the range of 0.10 to 5 MWel capacity it fluctuates within the limits of EUR 700 to 1 200/kWel. According to the forecasts, the relative price of cogeneration plant units with internal combustion engines of 0.1 – 5 MWel electrical capacity will remain stable in the 2004–2030 period, while the price of lower capacity units is likely to decrease slightly. The summarized data are presented in table 5-11.

Cogeneration plants with gas turbines

The basic package of cogeneration plant units with gas turbines comprises the following components: gas turbine, reducer, electricity generator, feeding and abstraction pipelines (for fuel, air, combustion products and heat transfer fluids), filters of air supplied for combustion, lubrication and cooling systems, standard unit launching system and noise silencers. Frequently, the standard package does not include a compressor for gas fuel fed into the turbine, heat utilization and water treatment systems, as well as installations for reduction and monitoring of environmental emissions of pollutants. The price of the main module of a gas turbine, taking into account the need for additional equipment (depending on the peculiarities of a specific consumer of power and heat, the environmental requirements, the necessity of connection to external power networks as well as other factors), represents the total costs of a cogeneration plant (the entire system). The latter, together with the envisaged design, installation, project management and additional material costs represent the total investments.

Summarized results of the total relative investments in cogeneration plants with gas turbines, as specified in various sources, are presented in table 5-16.

Fig. 5-16. Total relative project costs of cogeneration plant units with gas turbines

As we see, investments in gas turbine systems of different capacities differ within rather broad limits, depending on the existing market conditions, the requirements applicable to the technical and environmental requirements for power plants, and other factors. According to two reference sources [11 and 14], the data presented in figure 5-16 nearly coincide within the 1 – 20 MWel capacity range. For the year 2005, the relative investment costs specified in the references [14] exclude land plot preparation, administration, consulting and project management expenses. After estimation of the components representing project development and implementation costs according to the references [11,12], the total investments are obtained, which are similar to the data presented in the references [19]. It is noteworthy that the economic indicators specified apply to those gas turbines whose electricity production efficiency at basic load is roughly 42%.

Thus, the relative investment price for 0.1 – 40 MWel capacity units ranges from EUR 650 to EUR 1 950/kWel. The price of the main module of a gas turbine within the 5 to 40 MWel capacity limits decreases insignificantly, however the relative (EUR/kWel) price of auxiliary equipment (i.e. heat reclaim unit, gas compressor, water treatment installations etc) declines significantly, resulting in somewhat lower relative investments in the whole plant.

According to the forecasts, the price of 5–125 MWel capacity units will remain stable until 2030, but will decline insignificantly for gas turbines with a 0.1–1 MWel capacity. The summarized data are presented in table 5-11.

Cogeneration plants with steam turbines

The relative price (EUR/kWel) of units for steam turbines with low or medium electricity production efficiency, compared with the other modules of cogeneration plants, is rather competitive and changes within the boundaries of EUR 300 to EUR 1000/kWel in the markets of various countries. However, an increase in the relative investments in a fully assembled system (boiler + turbine) is substantial. This augmentation of the relative price of equipment owes not only to the high price of the steam production boiler of high parameters but also to the low ratio between the generated power and heat, which predetermines a relatively low efficiency of electricity production of the system. The achieved electricity production efficiency is much lower than that of power plants with gas turbines, combined cycle or internal combustion engines, and often only 6 – 15% of fuel energy is converted to electrical energy (systems of small steam parameters).

It is often economically expedient to install steam turbines of low electricity production capacity into the already used boiler-houses with steam boilers, taking full advantage of the existing steam boilers and all additional equipment.

Many industrial (AB Paj•rio mediena, UAB Arvi cukrus, AB Lifosa, AB Danisco Sugar Panev•žys and AB Grigišk•s) and DH companies (in Druskininkai, Panev•žys, Klaip•da and Šiauliai) are using low electric efficiency, low capacity steam turbines. The working pressure of the existing boilers is too low to ensure effective operation of steam turbines (saturated < 25 bar), and the steam temperature is usually close to the saturation temperature. Therefore, the efficiency of electricity production does not exceed 10-15%. An analysis of the technical parameters achieved by the systems operating under the Rankine cycle in other counties shows that the electrical efficiency potential of the low-efficiency units operating under the Rankine cycle in Lithuania may be significantly enhanced [20].

The relative equipment prices published in different sources usually refer to the module of a fully assembled boiler, steam turbine and electricity generator. Installation of a medium and high efficiency steam turbine next to the existing boilers or within a combined cycle costs EUR 300-800/k/Wel, figure 5-17, dotted line, [21].

Fig. 5-17. Total relative project prices for cogeneration plants with steam turbines

The price of an electricity generator usually amounts to 20-40% of the price of the whole module [12]. The costs of installation of a boiler producing steam of high parameters accounts for the lion's share of capital expenses (including the fuel feeding system, which is necessary for solid fuel, as well as technologies reducing the emissions of pollutants into the environment). Thus, the price of steam power plants specified in the references [11] is suspiciously low. The total standard price of equipment and installation of a solid fuel cogeneration plant with a steam turbine far exceeds EUR 1 500 kWel and rises sharply with a decrease in installed electric capacity (concerns systems with an electric efficiency coefficient above 15-20%). Data supplied by Danish experts on modern technologies [14] highlight the fact that low-capacity (0.6-4.3 MWel) steam turbines achieve an electric efficiency of 25% and efficiency enhancement in units of such capacity is no longer expected. This means that the limit of eclectic efficiency in low-capacity units has already been reached, and further improvement of productivity is economically inexpedient. The relative installation price for low capacity units is already 4-6 times above that for units with a >400 MWel capacity. Forecasts on the expected changes in the prices of steam turbines with a 0.6-4.3 MWel capacity are introduced by table 5-10.

Table 5-10. The relative investment price for biofuel power plants with steam turbines

Year	2004	2010-2015	2020 - 2030
Relative price, €/kW*	4200 - 5700	3400 - 4700	2800 - 3800

Summarized data are presented in table 5-11.

Combined cycle cogeneration plants

Since a short description of cogeneration plants with steam and gas turbines was offered in the preceding chapters, a detailed description of combined cycle will not be presented.

In principle, combined cycle power plants are distinguished for small relative investments (smaller than investments in gas or steam turbines and internal combustion engines) and high efficiency of electricity production.

The relative investments of cogeneration plants with combined cycle systems are reflected in figure 5-18.

Fig. 5-18. Total relative project prices for cogeneration plants with combined cycle systems

From the analysis of the references [11, 14, 17] we can see that the relative investment price for combined cycle power plants with capacities lower than 200 MWel increases significantly as the installed electrical capacity decreases. The relative installation price represented by the dotted line excludes project development and implementation costs. The continuous blue line represents the total costs per unit of electrical capacity.

The economic indicators of the specified combined cycle power plants apply to power plants with an electrical efficiency of 46-54%. The investment prices of power plants with a capacity of 10-100 MWel, as illustrated in fig. 5-8, are expected to remain stable in the 2004-2030 period.

Summarized data are presented in table 5-11.

A summary of the main equipment and installation costs for cogeneration plants

Table 5-11 presents the summarized relative equipment and installation costs for cogeneration plants with internal combustion engines, gas or steam turbines and combined cycle.

Table 5-11. Summarized total relative costs of cogeneration plants

No	Type of main unit of cogeneration plant	Installed capacity, MW_{el}	Relative project price, €/kW_{el}	Price used in analysis, €/kW_{el}
1.	Internal combustion engine	0.5-5.0	750-900	825
2.	Gas turbine	5.0-40.0	650-1000	825
3.	Steam turbine + boiler	0.6-50	3500-5700	4600
4.	Combined cycle	10.0-100.0	680-1180	930

The information supplied in table 5-11 demonstrates significant differences in technology prices within the possible range of capacities. They depend on a number of factors (the level of technology automation, technical novelty etc.), which must be examined separately in each particular case in accordance with the specific local requirements. The economic assessment of the combined heat and power potential will use the average prices of investments required by an individual technology.

5.5.2 The costs of cogeneration plant maintenance and service

To a large extent, the maintenance and service costs depend on decisions in the preliminary stage (design, construction, equipment type/choice of package). The main costs of maintenance and service are categorized as follows:

- Labour costs. Depend on the size and automation level of a plant. Within the range of small capacities (up to 10 MWel of electrical capacity), cogeneration plants may operate without service staff at a fully automated mode. In medium capacity systems (10-30 MWel), service staff is necessary, but normally one person overseeing the technological processes is sufficient. In big systems, a service staff of two ore more is required. Solid fuel burning power plants inevitably require more service personnel due to constant fuel preparation and feeding needs. When cogeneration units are installed in already operating boiler houses, this component of costs may be equal to zero, depending on the circumstances.
- Operating costs. They represent the costs of spare parts, auxiliary materials and repairs (routine and major). The latter depend on the type of the cogeneration plant, the type of fuel used, the cycle of operation of the plant and on the culture of equipment use. If heavier fractions and lower quality fuel (such as fuel oil) are used in energy power and heat production, they system requires regular stops and launches, which boost the service and operation costs.
- Insurance. It also forms part of operating costs. Insurance may be taken out against unforeseen equipment failure, interruptions in production and supply, revenue decreases etc. This component of service costs depends on the type of the cogeneration plant, project solutions and equipment operation conditions and usually amounts to 0.25-2% of the full price of equipment.
- Other costs. Administrative costs, environmental pollution taxes, interest on loans etc.

Just like investments, service and maintenance costs are expressed in relative values, i.e. costs per installed capacity (1 kWel) over a certain period of time. Frequently, the service and maintenance costs accumulating during cogeneration plant operation are broken down into two components: the variable and the fixed part. The variable part is expressed in monetary costs per 1 unit of produced electricity (cent/kWh). The fixed part may also be recalculated per energy unit, specifying the hours of operation and the average load of the power plant units.

The fixed component of the costs includes all costs independent from the power plant load and time of operation, i.e. the wages paid to the management and service personnel, property taxes, insurance premiums etc. The dominant part in the fixed component of costs is the costs of wages.

The variable component of costs comprises the expenses on routine and major repairs, acquisition of auxiliary materials (water, oils, fuel additives), and repair, replacement and maintenance of various parts of the system. It should be noted that these are not fixed costs, as they depend on the time of operation of a unit. Thus, the specified operating costs for the life-cycle of a unit are average values. *Fuel costs are not included into operational costs.*

Cogeneration plants with internal combustion engines

The maintenance and service costs change depending on the type of internal combustion engines, the speed (frequency) of crankshaft rotation, the achieved electrical capacity and the number of engine cylinders. Normally, this type of costs includes:

- Operating costs: replacement of engine parts and renewal of other additional materials, i.e. replacement of fuel and air filters, plugs, gaskets, valves, piston rings, electronic parts, lubricants etc;
- Routine and major repairs.

The work can be performed either by company staff or contracted out to enterprises engaged in the relevant activities. Brief maintenance work (replacement of lubricant, air filters, coolant as well as plugs) is recommended every 1 000 hours of operation. The estimated resource until the repair of the cylinder head and turbo compressor is 2 000-10 000 hours of operation. Every 20 000-40 000 hours of operation, major repairs shall be carried out, covering the replacement of the piston and rings, sleeves, crankshaft bearings and gaskets. Although the use of internal combustion engines requires regular maintenance, the degree of wear and tear is best reflected in the analysis of engine oil composition. The relative operating costs of internal combustion engines with higher electrical efficiency are lower than the respective costs of lower capacity units, as illustrated by table 5-12 [16].

Table 5-12. Operating costs of power plants with internal combustion engines (EUR/MWhel)

€/MWh_{el}	Electrical capacity, MW_{el}				
	0.1	0.3	0.8	3	5
Fixed part	0.9	0.7	0.4	0.1	0.1
Variable part	11.2	9.8	8.7	7.4	7.0
Total costs	12.1	10.5	9.1	7.5	7.1

* Note. Assumed time of operation of units is 8 000 hrs. per year.

According to reference 14, the standard operating expenses on repairs for 1-5 MWel capacity units amount to EUR 6-9/MWh. It should be mentioned that these values nearly correspond to the those specified in reference 11. The relative operating costs for cogeneration plants of 1-5 MWel capacity with internal combustion engines are expected to retain stability in the 2004-2030 period. Summarized data are available in table 5-15.

Cogeneration plants with gas turbines

Routine service and maintenance covers regular inspection, testing and vibration monitoring, forecasted maintenance and preventive checks. Preventive checks are recommended every 4 000 hors and should include vibration monitoring and checks on the rotor, bearings and turbine blades. Every 12 000-50 000 hours of operation, major repairs shall be carried out. Typical major repairs shall include rotor replacement, renewal of turbine components (replacement of support and shaft bearings), replacement of worn out turbine blades etc.

It is noteworthy that operating costs are prone to significant changes depending on the operating conditions of a gas turbine. When a turbine is recharged or the set design electrical capacity is exceeded, burning of liquid fuel with a lot of additives greatly increases the probability of both routine and major repairs.

The relative operating costs of higher electrical capacity gas turbines are smaller compared with lower capacity units. The summarized indicators of operating costs are presented in table 5-15.

Table 5-13. Operating costs of cogeneration plants with gas turbines

No	Reference	Relative/fixed* /variable costs €/MWh_{el}	Capacity, MW_{cl}					
			1	5	10	40	100	125
1.	[9]	Variable costs component	3.9	3.9	3.9	3.0	-	-
		Fixed costs component	4.2	1.1	0.8	0.5	-	-
		Total operative costs	8.1	5.0	4.7	3.5	-	-
2.	[4]	Variable costs component	-	8.0	-	2.8	-	2.0
		Fixed costs component	-	1.0	-	1.0	-	0.8
		Total operating costs	>7	9.0	-	3.8	-	2.8
3.	[1]	Total operating costs	<5.4	-	-	-	4.6	-
Average values			7.7	7.0	4.7	3.7	-	2.8

* Note. Assumed time of operation of units is 8 000 hrs. per year.

As we can see, maintenance and service costs based on the data supplied by different countries, including the same components of costs, differ by 30% on average. In summary, it may be stated that the total operating costs for a 1-125 MWel capacity turbine using natural gas amount to EUR 3-8 MWh. In the 2010-2030 period, the operating costs of 0.1-5 MWel capacity gas turbines are expected to slump, while the variable share of costs of a 5 MWel capacity will amount to EUR 4/MWh. Summarized data can be found in table 5-15.

Cogeneration plants with steam turbines

Steam turbines are known for durability with a life cycle up to 50 years. Service and maintenance is simple, however continuous monitoring of steam supplied to the turbine as well as of turbine bearing lubricant impurity due to various additives, its amount and temperature is necessary. Maintenance also include monitoring of pumps, coolers, lubricant filters as well as gas turbine recharging devices.

The operating costs may be boosted by thermal stress occurring in the steam pipeline during or outside operation time. In order to reduce the impact of thermal stress and to reduce the wear and tear of equipment, a long system launching period is required

Increasing of the parameters of steam supplied to the turbine (pressure, temperature) inevitably raises both the capital and service costs.

The total annual operating costs of 0.6-4.3 MWel units account for 3-4% of capital costs, 2% of which can be attributed to the fixed operating costs component. The component of variable costs totals EUR 7.1/MWh. The total operating costs of high capacity systems (>100MWel) per 1MWhel may be more than 50% lower [14, 22]. Summarized data are presented in table 5-15.

Combined cycle cogeneration plants

Since a detailed overview of the operating expenses of cogeneration plants with gas and steam turbines was presented in the preceding chapters, a detailed analysis of the service and maintenance costs of combined cycle power plants is not offered here.

Thanks to the high efficiency of electricity production, the operating costs of combined cycle power plants are among the lowest compared to the respective costs of internal combustion engines as well as gas and steam turbines.

Specified in different sources, the total relative operating costs of combined cycle cogeneration plants differ up to 40%. The difference in the indicators of operating costs is especially remarkable when comparing the USA and EU Member States. The standard maintenance and service costs in the systems of 4-100 MWel capacity combined cycle cogeneration plants in the EU ranges from EUR 3.25 to EUR 5.40/MWh [11, 14]. As the installed electrical capacity increases, the variable operating costs component declines, while that of fixed operating costs increases, as illustrated by table 5-14. [14]

Table 5-14. The structure of the variable and fixed components of combined cycle power plants in the total operating costs

No	Relative/fixed*/variable costs, €/MWh_{el}	MW_{el}		
		10	100	400
1.	Variable costs component	3.5	1.75	1.50
	Fixed costs component	1.25	1.50	1.75
	Total operating costs	4.75	3.25	3.25

* Note. Assumed time of operation of units is 8 000 hrs. per year.

Summarized data are presented in table 5-15.

Summary of maintenance and service costs of cogeneration plants

Summarized total operating costs of cogeneration plants with internal combustion engines, gas or steam turbines as well as combined cycle plants are presented in table 5-15.

Table 5-15. Standard total operating costs of cogeneration plants

No	Type of main unit of cogeneration plant	Installed capacity, MW_{el}	Operating costs, €/MWh_{cl}	Costs value used in analysis, €/MWh_{cl}
1.	Internal combustion engine	0.5 - 5.0	6 - 11	8.5
2.	Gas turbine	5.0-40.0	4 - 8	6
3.	Steam turbine	0.6 - 50	2 - 4 % of investments per year	14.2*
4.	Combined cycle	10.0-100.0	3.25 - 5.4	4.3

* Note. Assumed time of operation of units is 8 000 hrs. per year.

The information presented in table 5-15 shows that the standard total operating costs of cogeneration plants differ significantly within the possible range of capacities. They depend on a number of factors (the level of technology automation, technical novelty etc.), which must be examined separately in each particular case in accordance with the specific local requirements. The economic assessment of the combined heat and power potential will use the average operating costs of an individual technology.

5.6 Technical potential according to the useful heat market and relevant combined heat and power production technologies

Information on heat demand was collected from all available sources such as special heat sector plans prepared by municipalities, interviews (industry) and the statistics, which are submitted to the National Control Commission for Prices and Energy by the enterprises generating more than 5 GWh of heat every year (TKG tables).

Heat demand was analysed in the following sectors:

- The district heating sector (heating, ventilation, domestic hot water)
- The industry sector (steam / heating water / mechanical energy)

5.6.1 Evaluation of the potential in the DH system

When evaluating the likely technical potential of combined heat and power production in the DH sector the following algorithm of actions was selected:

1. Analysis of the specificity of the district heating sector. The concept of a heat demand chart and potential applications for all DH systems;
2. Separation of hydraulically independent district heating networks;
3. Availability of the primary source of energy, fuel, by separating the DH systems with the option of using natural gas;
4. Selection of the available priority technologies of cogeneration plants and creation of the essential preconditions (equipment working time, technological level, etc.);
5. Evaluation of the technical potential by envisaging the most expedient technologies according to the specificity of the DH system and fuel availability.

Heat demand and fluctuations in demand in the district heating system

One of the key factors determining the capacity, number and required technical characteristics (such as the option of load removal etc.) of heat production installations is demonstrated in the annual heat demand chart. This chart represents the function of the change in heat demand capacity within a certain period of time. Expression of the momentary heat demand (MW) with respect to time (per second) is not necessary in district heating systems due to the factor of non-simultaneity of energy consumption.

Graphs showing heat demand on a per-minute (10 min. average), daily (24 h average) and monthly (monthly average) are presented in Fig. 5-19.

Apkrovimas, MW – Loading, MW
paros vidutinis poreikis – average daily demand
minutinis poreikis – demand on a per-minute basis
vidutinis m•nesinis poreikis – average monthly demand
Laikas, val. – Time, h

Fig. 5-19 Chart of the 2003 actual heat demand in Petraši• nai urban sub-district, Kaunas

A chart of heat demand expressed in the daily average will be used in this work. When selecting the daily average of heat demand instead of the heat demand average of 10 min a relative error does not exceed 3%, which, in fact, is sufficient accuracy for the optimisation of the load mode of heat production installations.

Evaluation of the potential of combined heat and power production by analysing every district heating system is a time-consuming but not unnecessary work. As an example, Fig. 5-20 presents the charts of heat demand of the country's four cities, located in different counties, expressed in the daily average and recalculated for the standard year.

Šilumos energijos gamybos galios poreikis, % – Heat production capacity demand, %
Metinis valand• skai•ius atitinkantis duot• šilumos energijos poreikio gali•, val./metus – The annual number of hours that corresponds to the given heat demand capacity, h/year

Fig. 5-20 Distribution and typical points of the annual heat demand

Heat demand charts of nearly all district heating systems can be characterised by four typical points:

Point No 1 shows the maximum heat demand capacity that is present only for several hours per year on the so-called coldest Friday.

Points No 2 and No 3 characterise the beginning and end of the heating season. Point No 3 also shows the maximum heat demand capacity of the non-heating season that consists of the peak of hot domestic water consumption, network losses and the maximum of industry demand for technological needs, if any.

Point No 4 characterises the minimum capacity of district heating demand that can be relatively assumed as equalling heat losses in the district heating network.

During the heating season and in particular at the beginning thereof heat demand charts significantly differ due to explicable reasons such as system size, climatic zone (coastal or continental area) and consumer specificity. But during the non-heating season heat demand charts nearly coincide. A relative error does not exceed 5%, which provides sufficient grounds for the application of the summarised heat demand load chart for any district heating system of the country. This is especially suitable for ensuring heat production unit's working time no shorter than 4 000-6 000 h/year. Analysis of the potential of combined heat and power production will use the average of the presented heat demand charts that conditionally evaluate the country's regional distribution.

The summarised value, i.e. the average capacity of heat demand corresponding to the arithmetic average of points No 2, 3 and 4 of the heat demand chart, describing the capacity of the heat demand during non-heating and transitional seasons, was selected for evaluation of the technical potential of combined heat and power production.

Separation of hydraulically independent district heating networks

With the aim of evaluating the technical potential of combined heat and power production in the Lithuanian district heating sector (production >5GWh), 220 hydraulically independent heating water networks supplying the residential sector, public organisations and industry with heat were analysed.

Part of DH systems (a total of 70 systems) with the average of the maximum heat capacity demand of 774 kW was not evaluated as potential systems. The customers of these systems are not supplied with heat in summer.

Distribution of the district heating sector according to fuel availability and the average heat demand capacity during non-heating and transitional seasons is presented in Fig. 5-21.

Vidutin• šilumos energijos poreikio galia ne šildymo ir pereinamajame sezone, MW – Average heat demand capacity during non-heating and transitional seasons, MW
n•ra gamtini• duj• – without natural gas
yra gamtini• duj• – with natural gas
Šilumos poreikio gali• ne šildymo ir pereinamajame sezone vidurkio intervalai, MW – Intervals of the average of heat demand capacities in non-heating and transitional seasons, MW
pastaba: informacija pateikta be Vilniaus ir Kauno miest• integruot• tinkl• – note: the information does not cover the integrated networks of Vilnius and Kaunas cities

Fig. 5-21 Distribution of the district heating sector according to fuel availability and the average heat demand capacity during non-heating and transitional seasons

Analysis makes the assumption that the evaluation of the DH systems that currently dispose of electricity generating power plants with their installed capacities being insufficient to fully satisfy the heat demand is required. The DH systems of Klaip•da, Panev•žys, Šiauliai, Marijampol•, Alytus, Druskininkai and some other cities can be treated as such systems.

Evaluation does not cover the influence of an independent heat supplier, in particular of industrial enterprises, on the potential of combined heat and power. This can be illustrated by the example of the Klaip•da city DH system in which waste energy from industrial enterprises and geothermal energy account for quite a big share in heat production.

Selecting priority technologies and creating preconditions determining the size of the technical potential

Analysis of priority electricity production technologies was made on the basis of statistical information about the prevalence of individual technologies worldwide. According to the information presented in references [11, 14] as the most prevalent technologies can be classified the following four systems with:

- Internal combustion engines;
- Gas turbines;
- Steam turbines; and
- Combined cycle (gas and steam turbines in a single system)

The main technical indicators of these systems, according to the technological level, are presented in Table 5-16.

Table 5-16 The world's most prevalent technologies for combined heat and power production

Internal combustion engines					
High electric efficiency			***Low electric efficiency***		
Electric ec	*Thermal ec*	*Total ec*	*Electric ec*	*Thermal ec*	*Total ec*
0.44	0.44	0.88	0.38	0.58	0.96
Gas turbines					
High electric efficiency			***Low electric efficiency***		
Electric ec	*Thermal ec*	*Total ec*	*Electric ec*	*Thermal ec*	*Total ec*
0.40	0.40	0.80	0.29	0.62	0.91

Steam turbines (p>40 bar)					
High electric efficiency			***Low electric efficiency***		
Electric ec	*Thermal ec*	*Total ec*	*Electric ec*	*Thermal ec*	*Total ec*
0.25	0.55	0.80	0.18	0.67	0.85
Combined cycle					
High electric efficiency			***Low electric efficiency***		
Electric ec	*Thermal ec*	*Total ec*	*Electric ec*	*Thermal ec*	*Total ec*
0.54	0.31	0.85	0.46	0.43	0.89

Technical parameters of equipment significantly differ depending on the manufacturer of the same technology. This is predetermined by the amount of investment in technology upgrading required by individual manufacturers as well as the by the target purpose. For instance, technological steam produced by the internal combustion engine of high electric efficiency (in a back-boiler) will not always meet technological demands due to the temperature or pressure of gas being lower than required (Carnot law). In this case, the installation of lower electric efficiency but ensuring production of gas of the required parameters is selected. Analysis of the technical potential was made on the assumption that the technological level meets the average of technologies present in the market.

Another important factor predetermining the size of the potential is the number of separate units capable of producing heat and power independently from each other planned to be installed in a cogeneration plant. The size of the technical potential was evaluated on the assumption that the DH system is installed with two units ensuring continuous electricity production that is not interrupted due to unavoidable operational stops (technical maintenance work etc.).

One more important factor determining the size of the technical potential is the level of capacity of load removal from a production installation or separate unit, i.e. what quantity of load can be technically removed from the installation compared to the nominal power production capacity. Evaluation of the technical potential was made on the assumption that each unit of a cogeneration plant is capable of a load removal of 35% of the nominal capacity even though the economically justifiable load removal value varies in the range of 40-60%. The assumed operation mode of cogeneration plant's units is presented in Fig. 5-22.

Šilumos energijos galia (MW) – Heat capacity (MW)
Termofikacijos •renginys Nr. 1 – Cogeneration installation No 1
Termofikacijos •renginys Nr. 2 – Cogeneration installation No 2
Katilai – Boilers
Šilumos energijos poreikis – Heat demand

Fig. 5-22 Operating modes of cogeneration plant units

The performed calculations show that power production would account only for 15% in a load removal interval between 35 and 50% and therefore the load removal limit of 35% is assumed in the evaluation of the technical potential.

According to the information presented in references [14], technical maintenance of internal combustion engines takes around 5% of the theoretically possible working period (8 760 h/year). Fig. 5-22 refers to half of the period necessary for technical maintenance during the heating season. During the non-heating season technical maintenance can be performed at any time in one of cogeneration plant units as the installed heat production capacity in the second one fully satisfies the demand of the DH system.

After evaluating the preconditions described above, the installable power production capacities corresponding to the average heat demand capacity during non-heating and transitional seasons at cogeneration plant units were obtained according to each of the technologies addressed. The obtained results are presented in Fig. 5-23.

$MW_{el.}/MW_{vid.š.apk.}$ (ne šildymo ir pereinamajame sezone) – MW $_{el}$/M $_{av\ heat\ load}$ (during non-heating and transitional seasons)
Vidaus degimo varikliai (1) – Internal combustion engines (1)
Duj• turbinos (2) – Gas turbines (2)
Garo turbinos (3) – Steam turbines (3)
Kombimuotas ciklas (4) – Combined cycle (4)

Share of DH demand produced at cogeneration plant

Fig. 5-23 Installable power production capacity in the DH system

According to the performed calculations the technical heat production potential of cogeneration plants would account for around 83 to 88% of the total heat demand in the DH systems. Subject to technology the installable power production capacity at the average heat demand varies between 1 MW and 4 MW during non-heating and transitional seasons.

Evaluation of the technical potential of combined heat and power production by selecting technologies according to the DH system specificity and fuel availability

Technologies were selected making the assumption that gas turbines are the most acceptable technology if the natural gas option is absent. According to the average capacity of non-heating and transitional seasons, in the case of natural gas option, technologies would distribute as follows:

- Up to 1MW – internal combustion engines;
- 1-5 MW – internal combustion engines;
- 5-15 MW – a combination of internal combustion engines and gas turbines;
- Over 15 MW – a combined cycle.

The technical potential of combined heat and power production according to the installable electricity production capacities is presented in Fig. 5-24.

Instaliuotina elektros energijos gamybos galia, MW – Installable power production capacity, MW
n•ra gamtini• duj• (biokuras) – without natural gas (biofuel)
yra gamtin•s dujos – with natural gas
Viso: – Total:
gamtin•mis dujomis - 881 MW– with natural gas – 881 MW
biokuru - 50 MW – with biofuel –50 MW
Šilumos energijos poreikio gali• ne šildymo ir pereinamajame sezone vidurkio intervalai, MW – Intervals of the average of heat demand capacities during non-heating and transitional seasons, MW

Fig. 5-24 The installable power production capacity in the Lithuanian DH sector without evaluating the integrated systems of Vilnius and Kaunas cities

The largest power production potential is concentrated in the major cities such as Klaip•da (246 MW), Šiauliai (108 MW), Alytus (106 MW) and Panev•žys (96 MW).

In the economic evaluation of combined heat and power production the additional installable capacities will considerably decrease first of all due to a low electric capacity of the units of cogeneration plants operating steam turbines. Also, as the Klaip•da case shows, the installable power production potential will decrease due to the existing non-independent heat producers (AB Paj•rio mediena) and the mandatory purchase of geothermal energy.

The installable technical potential of heat production is presented in Fig. 5-25.

Instaliuota šilumos energijos gamybos galia, MW – Installed heat production capacity, MW
n•ra gamtini• duj• (biokuras) – without natural gas (biofuel)
yra gamtin•s dujos – with natural gas
Viso: – Total:
gamtin•mis dujomis - 858 MW– with natural gas – 858 MW
biokuru - 148 MW – with biofuel –148 MW
Šilumos energijos poreikio gali• ne šildymo ir pereinamajame sezone vidurkio intervalai, MW – Intervals of the average of heat demand capacities during non-heating and transitional seasons, MW

Fig. 5-25 The installable heat production capacity in the Lithuanian DH sector without evaluating the integrated systems of Vilnius and Kaunas cities

The technical potential of the annual power production in the DH sector is presented in Fig. 5-26.

Metin• elektros energijos gamyba, MWh – Annual power production, MWh
n•ra gamtini• duj• (biokuras) – without natural gas (biofuel)
yra gamtin•s dujos – with natural gas
Viso: – Total:
gamtin•mis dujomis – 4 014 249 MWh – with natural gas – 4 014 249 MWh
biokuru – 214 449 MWh – with biofuel –214 449 MWh
Šilumos energijos poreikio gali• ne šildymo ir pereinamajame sezone vidurkio intervalai, MW – Intervals of the average of heat demand capacities during non-heating and transitional seasons, MW

Fig. 5-26 The technical potential of annual power production in the DH system without evaluating the integrated systems of Vilnius and Kaunas cities

Evaluation of the 2004 actual power production amounts in Vilnius and Kaunas integrated systems and the additional technical potential in the remaining DH sector shows that around 6 TWh of power could be produced per year. If replacement of the existing steam turbines with combined cycle technologies in the DH systems of Vilnius and Kaunas by installing the power capacities of 553 MWel and 286 MWel, respectively, is economically justifiable the annual power production potential in the DH sector would increase up to 7.8 TWh.

The annual technical potential of heat production is presented in Fig. 5-27.

Metin• šilumos energijos gamyba, MWh – Annual heat production, MWh
n•ra gamtini• duj• (biokuras) – without natural gas (biofuel)
yra gamtin•s dujos – with natural gas
Viso: – Total:
gamtin•mis dujomis – 3 957 780 MWh – with natural gas – 3 957 780 MWh
biokuru – 635 197 MWh – with biofuel –635 197 MWh
Šilumos energijos poreikio gali• ne šildymo ir pereinamajame sezone vidurkio intervalai, MW – Intervals of the average of heat demand capacities during non-heating and transitional seasons, MW

Fig. 5-27 Technical potential of the annual heat production in the DH sector without evaluating the integrated systems of Vilnius and Kaunas cities

The annual fuel consumption corresponding to the technical potential of heat and power production is presented in Fig. 5-28.

Metinis kuro suvartojimas, tne. – Annual fuel consumption, toe
n•ra gamtini• duj• (biokuras) – without natural gas (biofuel)
yra gamtin•s dujos – with natural gas
Viso: – Total:
gamtin•mis dujomis – 773 130 toe – with natural gas – 773 130 toe
biokuru – 88 102 tne – with biofuel – 88 102 toe
Šilumos energijos poreikio gali• ne šildymo ir pereinamajame sezone vidurkio intervalai, MW – Intervals of the average of heat demand capacities during non-heating and transitional seasons, MW

Fig. 5-28 The annual fuel consumption corresponding to the technical potential of heat and power production without evaluating the integrated systems of Vilnius and Kaunas cities

When evaluating the costs of fossil fuel corresponding to the technical potential of heat and power production a calorific value of 9.3 MWh/1 000 Nm^3 for natural gas and a calorific value of 2.0 MWh/t for biofuel were assumed (the average of DH enterprises).

A geographical distribution of the technical potential of combined heat and power production was performed on the basis of counties. The analysis results are presented in Fig. 5-29.

Instaliuotos elektros energijos gamybos galia, MW – Installed power production capacity, MW
n•ra gamtini• duj• (biokuras) – without natural gas (biofuel)
yra gamtin•s dujos – with natural gas
Vilniaus – Vilnius
Kauno- – Kaunas
Klaip•dos – Klaip•da
Panev•žio – Panev•žys
Alytaus – Alytus
Utenos – Utena
Marijampol•s – Marijampol•
Šiauli• – Šiauliai
Taurag•s – Taurag•
Telši• – Telšiai
Apskritys – counties

Fig. 5-29 Distribution of the technical potential of combined heat and power production according to counties without evaluating the integrated systems of Vilnius and Kaunas cities

As Fig. 5-29 shows, the geographical distribution for the most part depends on the technical potential utilised in major cities and therefore new units of cogeneration plants should first of all be constructed in these DH systems.

5.6.5 Industry

With the aim to analyse the potential of combined heat and power production at industrial enterprises an extensive questionnaire was worked out and sent to 252 industrial enterprises. A list of such enterprises is presented in Annex 5. Enterprises were selected using statistics on annual power costs. So far less than half of the enterprises responded but more responses are expected.

According to the obtained data, around 79% of enterprises hold their own heat sources, 18% of these enterprises sell waste heat to the DT system. The main fuel used is gas or wood.

5.7 Economically justifiable potential

The aim of evaluation of the economically justifiable potential of combined heat and power production is to identify the cogeneration potential the utilisation of which would be effective all over Lithuania, i.e. would ensure the lowest cost of energy production with respect to all customers. For this purpose the evaluation model uses the economic social ("pure") prices of resources (for more information see 5.4), such as the price of fuels, the external costs of CO_2 emissions, but not the actual commercial prices of resources.

To identify the annual heat demand at different basic loads, the summary chart on heat demand for district heating systems in a standard year (see Fig. 5-20) is used in calculations. Analysis covers 3 different versions of the basic thermal load, 1, 5, and 15 MW, which, by their values comply with the conditional division into intervals of technological applications used for cogeneration, presented in Chapter 5.6.

Evaluation of the economically justifiable potentials of cogeneration consists of the comparison of the discounted total marginal costs of energy production of the long-term period between the two alternatives addressed:

In the first alternative, part of heat is generated in a cogeneration unit simultaneously generating the respective amount of power. The remaining amount of heat is generated in new hot-water boilers.

The second alternative means energy production other than cogeneration, i.e. the total required heat is generated in new hot-water boilers and the respective electricity amount (that equals the amount generated in the first alternative) is supplied from a thermal power plant operating in a condensing mode.

The economic evaluation result is presented as the total discounted marginal energy production costs of the long-term period recalculated into the production expenditure on 1 MWh of power and 1 MWh of heat. Separation of power and heat production costs is based on the principle that the price of heat for consumers should not rise in case of setting up a cogeneration plant and therefore the costs of heat generated in the cogeneration plant are assumed to correspond to the costs of heat production in a boiler-house.

The economic evaluation result contains conclusions on the economic efficiency of the calculated technical potentials of cogeneration.

Investments and maintenance costs used in the evaluation comply with the values given in Chapters 5.5.1 and 5.5.2. Investments in the construction of new hot-water boiler-houses along with related preconditions are presented in Table 5-17.

Table 5-17 Investments in the construction of new hot-water boiler-houses, and related preconditions

Relative investment	LTL 103,500/MW [14]
Boiler-house COP	0.9
Variable costs	LTL1.38/MWh
Fixed costs	1.2% of initial investment/year
Thermal value of fuel (natural gas)	9.3 MWh/1 000 n m^3
CO_2 emission	0.2 t/MWh (fuel – natural gas)

Evaluation makes the assumption that in the second alternative the costs of power production in a thermal power plant correspond to the marginal costs of power production in the Lietuvos Elektrin•. It is assumed that the production costs of 1 MWh in this power plant equal LTL 108.8. The costs of production were calculated on the basis of Decision No O3-84 of the National Control Commission for Prices and Energy of 29 July 2004 Regarding the Rules for the Regulation of the Price of Electricity Purchase from Combined Heat and Power Producers. The evaluation uses these costs from the year 2010, i.e. after the INPP closure. In the period from the start of the evaluation to the closure of the INPP the comparative costs of power production are equated to the average power price at auction, i.e. LTL70/MWh [31].

The economic price of natural gas was assumed to equal the price of gas purchased by AB Lietuvos dujos for the year 2006 amounting to LTL 355/1 000 n m^3 (LTL 38.13/MWh). The change of this price in the period addressed corresponds to the forecast presented in Chapter 4.4.

Identification of the technical potential of combined heat and power in Chapter 5.6.1 was based on two criteria, i.e. ensuring energy supply security (construction of two power production units) and technically feasible degree of load removal from the unit (the minimal thermal load at the presence of which the unit fully maintains its technical parameters, temperature, pressure, etc.).

The afore-mentioned principles were also used when evaluating the economic potential of cogeneration. This means that two cogeneration units of identical capacities with their work loads subject to falling to 50% of the nominal capacity were selected. The minimal thermal load of the unit is determined according to the capacity of the heat demand during non-heating and transitional seasons. The economic preconditions used in the evaluation are presented in Table 5-18.

Table 5-18 Preconditions used in the evaluation of the economically justifiable potential

Discount rate	4%
Period addressed	2006-2030
Interest rate	7.5%
Loan repayment term	10 years
Litas/euro exchange rate	LTL/EUR 3.45

As determined in the performed economic evaluation, the cogeneration technology to be used in the district heating systems with the heat demand capacity up to 1 MW during non-heating and transitional seasons is internal combustion engines (ICE). The economic calculation results are presented in Fig. 5-30.

Diskontuoti 1MWh elektros ir šilumos energijos gamybos suminiai ekonominiai ilgo periodo kaštai, Lt – The total discounted economic production costs of 1 MWh of heat and power of the long-term period, LTL
Elektros energija – Electricity
Šilumos energija – Heat
Termofikacija – Cogeneration
Ne termofikacija – Non-cogeneration

Fig. 5-30 Economic calculation results when the heat capacity in DH systems during non-heating and transitional seasons reaches 1 MW.

The discounted marginal production costs of 1 MWh of power and heat of the long-term period when the heat demand in DH systems during non-heating and transitional seasons reaches 5 MW are presented in Fig. 5-31.

Diskontuoti 1MWh elektros ir šilumos energijos gamybos suminiai ekonominiai ilgo periodo kaštai, Lt – The total discounted economic production costs of 1 MWh of heat and power in the long-term period, LTL
Elektros energija – Electricity
Šilumos energija – Heat
Termofikacija – Cogeneration
Ne termofikacija – Non-cogeneration

Fig. 5-31 *Economic calculation results when the heat capacity in DH systems during non-heating and transitional seasons reaches 5 MW.*

Based on the existing good practice the technologies installable in the thermal load interval of 5-15 MW are ICE and gas turbines (GT). The total economic costs of the long-term period are presented in Fig. 5-32.

Diskontuoti 1MWh elektros ir šilumos energijos gamybos suminiai ekonominiai ilgo periodo kaštai, Lt – The total discounted economic production costs of 1 MWh of heat and power of the long-term period, LTL
Elektros energija – Electricity
Šilumos energija – Heat
VDV – ICE
DT – GT
KCJ – CCPP
Ne termofikacija – Non-cogeneration

Fig. 5-32 The total economic costs of 1 MWh of the long-term period are presented according to separate technologies at the thermal load of 15 MW during non-heating and transitional seasons

Installation of both the ICE and the GT technologies at the thermal load of 15 MW during non-heating and transitional seasons produces a positive economic effect.

The recommended margin from 15 MW for the installation of combined cycle cogeneration plants also satisfies the economic assessment criterion, i.e. the total discounted marginal costs of 1 MWh of power of the long-term period are lower than the costs of production of the same energy amount separately in a thermal power plant (operating in a condensing mode) and a traditional hot-water boiler-house.

In summary of the economic evaluation results of the cogeneration potential, it can be stated that utilisation of the indentified technical potential of cogeneration is economically efficient.

During financial assessment of the alternatives the present commercial prices of resources were used. The price of natural gas is assumed to amount to LTL 420/1 000 n m^3, but the external costs of CO_2 emissions are not taken into account (it is assumed that the power plant will not exceed CO_2 emission limit values). The comparative commercial cost of power production from the year 2011 is assumed to total LTL 127.3/MWh (the same methodology as in the case of the economic price assessment was employed for this identification).

The obtained results of financial assessment in the thermal capacity interval to 1 MW are presented in Fig. 5-33.

Diskontuoti 1MWh elektros ir šilumos energijos gamybos suminiai finansiniai ilgo periodo kaštai, Lt – The total discounted financial production costs of 1 MWh of heat and power of the long-term period, LTL
Elektros energija – Electricity
Šilumos energija – Heat
Termofikacija – Cogeneration
Ne termofikacija – Non-cogeneration

Fig. 5-33 Financial calculation results when the heat capacity in DH systems during non-heating and transitional seasons reaches 1 MW.

Diskontuoti 1MWh elektros ir šilumos energijos gamybos suminiai finansiniai ilgo periodo kaštai, Lt – The total discounted financial production costs of 1 MWh of heat and power of the long-term period, LTL
Elektros energija – Electricity
Šilumos energija – Heat
Termofikacija – Cogeneration
Ne termofikacija – Non-cogeneration

Fig. 5-34 Financial calculation results when the heat capacity in DH systems during non-heating and transitional seasons reaches 5 MW

It is obvious that using the real prices of resources the installed cogeneration technologies produce similar (5 MW) or larger (1 MW) total financial costs of the long-term period. The financial assessment results at the basic thermal load of 15 MW are presented in Fig. 5-35.

Diskontuoti 1MWh elektros ir šilumos energijos gamybos suminiai finansiniai ilgo periodo kaštai, Lt – The total discounted financial production costs of 1 MWh of heat and power of the long-term period, LTL
Elektros energija – Electricity
Šilumos energija – Heat
VDV – ICE
DT – GT
KCJ – CCPP
Ne termofikacija – Non-cogeneration

Fig. 5-35 Financial assessment results at the thermal load of 15 MW during non-heating and transitional seasons

The obtained results show that (taking into account the assumed preconditions regarding investment, maintenance costs, fuel prices, etc.) the costs of energy generated from cogeneration through the employment of ICE and GT technologies are lower, whereas they exceed the financial costs of energy production in a combined cycle cogeneration plant when energy is produced in other manner than cogeneration: a combined cycle power plant operating in a condensing mode and a new hot-water boiler-house.

In the DH systems without natural gas a potential type of fuel for the process of cogeneration is wood. The applied cogeneration technology is ST. The results of the performed economic evaluation of energy production are presented in Fig. 5-36.

Diskontuoti 1MWh elektros ir šilumos energijos suminiai ekonominiai ilgo periodo ribiniai kaštai, Lt – The total discounted economic marginal costs of 1 MWh of heat and power of the long-term period, LTL
Elektros energija – Electricity
Šilumos energija – Heat
Ne termofikacija – Non-cogeneration

Fig. 5-36 Economic evaluation results of energy production

As the Fig. above shows, at the thermal load of 15 MW (the costs of energy production in units of lower capacity increase) steam turbine operated cogeneration units burning wood fuel generate higher total marginal costs of the long-term period. Such results of ST technologies can be explained, first of all, by a high requirement for investment in ST technologies and a relatively low electrical efficiency. Despite the obtained unfavourable results of economic evaluation regarding ST, it should be emphasised that apart from conditionally high costs of energy production, the ST technology is one of the means allowing achievement of the strategic goals set for the energy sector, i.e. a 12% share of renewable energy resources in the total energy balance until 2010; the reduction of CO_2 emissions; the security of energy supply and the diversification of fuels. Another important criterion for the promotion of this technology is additional job creation. In summary of these criteria it can be stated that the technical potential of cogeneration is economically justifiable.

When identifying the actual economically justifiable potential of cogeneration in Lithuania, account was taken of the economic analysis results as well as the cogeneration units currently being constructed in

Panev•žys, Alytus and Marijampol•. Also, heat supply from independent heat suppliers, UAB Geoterma and AB Paj•rio mediena, to the Klaip•da DH system was separately evaluated.

In the second half of 2006, construction of a cogeneration unit of 25MW electric capacity and of the same thermal capacity with its minimal capacity corresponding to the basic load during the non-heating season is planned to be completed in Panev•žys. After evaluating the setting up of the new unit, the economically justifiable potential of cogeneration in the Panev•žys DH system decreases to 48 MW.

By the end of 2006, construction of the cogeneration unit of 9MWel/32MWht in Alytus should be completed. The remaining potential of cogeneration would total 53 MW.

The technical potential of cogeneration identified for the Klaip•da DH system reaches 246 MW; however, taking into account heat purchased from independent suppliers the actual economically justifiable potential decreases to 90 MW.

The actual economically justifiable potential of cogeneration totals 610.9 MW in the DH systems with the option of natural gas and 43.9 MW in the systems without the natural gas fuel. The installed potential of cogeneration according to DH groups is presented in Fig. 5-37.

Instaliuota elektros energijos gamybos galia, MW – Installed power production capacity, MW
N•ra gamtini• duj• – Without natural gas
Yra gamtini• duj• – With natural gas
Vidutini• šilumos energijos poreikio gali• ne šildymo ir pereinamajame sezone intervalai, MW – Intervals of the average heat demand capacities during non-heating and transitional periods, MW

Fig. 5-37 Installed cogeneration potential according to DH groups

The installed heat capacity totals 645.6 MW in the DH systems with the option of natural gas, and 115.4 MW in those without this option. The total annual amount of generated electricity totals 2 830.52 GWh (when using natural gas) and 178 GWh (when burning other fuel than natural gas). Investments required for the utilisation of the cogeneration potential amount to LTL 697 353 000 in the DH systems without natural gas.

5.8 Analysis of risks to the utilisation of the economically justifiable combined heat and power potential

When analysing the economically justifiable potential of combined heat and power production, the following types of risk can be pointed out:

3. Commercial risk

   a. Fuel availability risk
   The main type of fuel used for the production of combined heat and power is natural gas. The price of natural gas mainly depends on external factors (see Chapter 4.4). Inside the country, the price of gas depends on the amount of natural gas consumed by customers, the place of connection to a gas supply network (distribution or main pipeline) and the supplier of natural gas. The change of the price of natural gas is part of commercial activities.

   b. Heat market risk
   Combined heat and power production is greatly dependent on the heat market. Pursuant to the currently applicable legislation, municipalities should work out special plans of the

heat sector providing for heat sector development for the long-term period. The plans are used to identify heat supply areas by indicating the economically justifiable method of heat supply. Having clear district heating areas and at the same time the target share of the heat market, the likely potential of cogeneration in the DH sector is conditionally defined.

c. Power market risk

The power market is conditionally open. Lithuania's import capacities account for up to 50% of the current production capacities and therefore power producers are likely to face a stronger foreign competition in the future. However, it should be noted that the Lithuanian energy system has the tightest connection with the countries that do not have sufficient production capacities for power export and therefore the increase of competition is still rather limited. The Lithuanian energy system has no sufficient connection to the EU system and therefore trade in electricity with Western Europe currently is not possible. It is not clear when projects of connection line installation are finished and most probably they will be completed no earlier than in 2009.

d. Investment risk

Heat supply companies and municipalities lack investment capital. No special financial institutions to finance combined heat and power projects, such as special funds or other financial groups, are set up. Commercial banks have a favourable attitude to energy projects but the amount of loans being extended greatly depends on the financial performance of companies. Thus, the economically expedient maximum capacity of installations may be limited.

e. Interest rate risk is related to companies' financial indicators, amount of liquid assets, etc.

f. Inflation.

4. Technical risk

a) Quality of installations. This risk is easily managed by selecting experienced suppliers and demanding quality guarantees from the manufacturers.

b) Power transmission and distribution networks essentially satisfy the current demands of the power system but considering their age, investments will be necessary to maintain the networks' current condition, satisfy the increasing requirement for the reliability of power supply and create a single power market of the three Baltic States.

c) The country's natural gas system is sufficiently developed with regular investments going to its modernisation and development and therefore the likely risk in this sector is related only to the parameters of natural gas such as the lack of pressure for combined cycle technologies.

5. Legal/administrative risk

a) Heat tariffs

Heat tariffs are approved by the National Control Commission for Prices and Energy. Its calculations are based on the variable and fixed production costs, including depreciation and the normative profit component.

b) Electricity tariffs and quotas

Pursuant to the purchase amounts set by the Ministry of the Economy, the National Control Commission for Prices and Energy sets the prices (tariffs) of electricity to be purchased. Sizes of the quotas and electricity tariffs are set for every year taking account of the scale of electricity purchase satisfying the public interests of that year.

6 Analysis of legislation regulating cogeneration

Legislation regulating combined heat and power production can be divided into legislation governing the power sector and that regulating the heat sector. Both these sectors are regulated by the Law on Energy adopted by the Seimas of the Republic of Lithuania on 16 May 2002 (a new version of this Law will come into effect on 1 January 2006). Apart from legislation regulating the operation of these sectors, combined the heat and power production is regulated by legislation governing the fuels sector (natural gas, local and renewable sources).

The Law on Energy regulates general energy activities and lays down the basic principles of energy development and management. Operation peculiarities of individual energy systems and relations between companies and customers are regulated by other laws and subordinate legislation.

Pursuant to the Law on Energy the principal objectives of regulation of energy sector activities are:

security of energy supplies;

efficiency of energy resources and energy consumption;

reduction of adverse effects of energy activities on the environment;

promotion of fair competition;

promotion of consumption of local and renewable energy resources.

The Law on Energy contains the main provisions related to combined heat and power production:

1. According to the Law on Energy activities in the energy sector shall be subject to licences or authorisations. The rules of issuing licences or authorisations shall be approved by the Government or an institution authorised by it. Licences for energy production and electricity production capacities development shall be issued by the Ministry of the Economy.

2. The Government or its authorised institution shall establish the procedure for purchasing the electricity generated from renewable energy resources and at cogeneration plants;

3. Energy facilities of national importance shall be developed according to the provisions of the National Energy Strategy. Energy facilities of national importance mean power plants with the total installed capacity of all generators larger than 50 MW. Planning of their construction must be carried out according to the Regulations for the Planning of Construction of the Energy Facilities of National Importance approved on 8 March 2005. Development plans related to electricity production at cogeneration plants with a capacity over 200 MW should be formulated at least five years before the expected commencement of these investment projects (according to Council Regulation No 736/96/EEC). Development plans related to unlisted energy facilities of national importance or those that do not meet the parameters specified in Council Regulation No 736/96/EEC should be prepared at least one year before the commencement of construction of these facilities. This requirement is applicable to cogeneration plants with an electric capacity of more than 50 MW.

4. Prices in the energy sector shall be contract and state regulated prices. Prices shall be regulated by approving the prices of a service or energy, establishing their price caps or the procedure of

regulation. The tariffs and principles of regulation of the state regulated prices shall be laid down in the laws of appropriate energy system.

5. When setting the state regulated prices, provisions have to be made for obligatory expenses for extraction of energy resources, energy production, purchasing, transmission, distribution and supply as well as for the development of the energy sector and energy efficiency, the use of local and renewable resources, implementation of public service obligations and the set profit rate.

6. Energy enterprises engaged in the activities the prices whereof are regulated shall co-ordinate prospective investment with the National Control Commission for Prices and Energy (hereinafter referred to as the Commission). Where such investment of the energy enterprises is not co-ordinated with the Commission, it may not be recognised as reasonable.

6.1 Electricity sector

The electricity sector is additionally regulated by the Law on Electricity adopted by the Seimas of the Republic of Lithuania on 20 July 2000 (the latest version was adopted on 1 July 2004).

The Law on Electricity establishes the basic principles regulating the production, transmission, distribution, and supply of electricity with account of the requirements of European Union legislation. It formulates relations between suppliers of electricity and their customers, and establishes conditions for the development of competition in the electricity sector. The application of this Law as well as of other legal acts necessary for the implementation of this Law in the electricity sector is supervised by the Commission.

The Law on Electricity stipulates the main provisions related to combined heat and power production (cogeneration plants):

1. All producers shall have the right to supply their divisions, subsidiaries and eligible customers with electricity through a direct line.

2. The Government or a body authorised by it may charge transmission or distribution operators or other electricity suppliers with public service obligations. The costs of fulfilling public service obligations shall be included in electricity tariffs for consumers.

3. Electricity production at cogeneration plants, when the latter supply heat to district heating systems of towns and cities and also ensure an electricity production reserve, is considered to be a service in the public interest in the energy sector.

4. When imposing public service obligations the State encourages producers to generate electricity from renewable sources of energy.

5. Prices of electricity sold by the producers and independent suppliers as well as prices for the capacity reserve are not regulated, except in the cases where producers and independent suppliers have more than 25% of the market share. Prices shall be set by the mutual agreement of the parties or by auction. Prices for the producers and independent suppliers having more than 25% of the market share shall be set by the Commission according to the mandatory expenses and the maximal amount of electricity.

6. Any person may become an electricity producer upon being granted the required authorisation. Expansion of the existing electricity production capacities and installation of new production capacities in a new location shall be subject to authorisation to expand the electricity production capacities. Authorisations shall be granted to all applicants who guarantee that activities carried out

by them will satisfy the criteria set out in the Law, i.e. those relating to safety of installations and their compliance with the requirements for environment protection and energy consumption efficiency, technical, economic and financial capabilities, respect of public service requirement, etc. The granting of an authorization may not be refused for any other reasons than non-compliance with the requirements laid down in this Law. An application to issue an authorisation for electricity production submitted by the enterprise the technological electricity production capacity of which exceeds the total (heat and power) capacity of 10 MW shall be accompanied by a document showing the enterprise's capacity to accumulate and maintain the stocks of reserve fuel.

7. Requirements for the design and construction of new electricity generating capacity shall be laid down in the Law on Construction and other legal acts.

Purchase and promotion of electricity from cogeneration:

Combined heat and power production is promoted. Pursuant to the Laws on Heat Sector and the Law on Electricity, the Procedure for Purchasing Electricity from Co-generators of Heat and Power, setting the scope of and procedure for the purchase for every year, has been approved.

The Minister for the Economy sets the annual scope [GWh] of and the procedure for the purchase of electricity from co-generators of heat and electricity as well as the forecast of this scope for another two years taking regard of the stated total estimated amount of electricity to be sold, the actual electricity supply for the past three years, electricity requirement forecast and the provision of the National Energy Strategy stating that cogeneration plants should produce from 35 to 45% of the total electricity produced in the country in 2015-2020.

The scope of purchase and its forecast are set on the assumption that the annual growth of electricity production from cogeneration after the shutdown of Unit 1 of the Ignalina NPP in 2005 until the shutdown of Unit 2 of the Ignalina NPP in 2010 will amount to 100 GWh per year.

If the stated total estimated electricity amount planned to be sold by all producers does not exceed the scope of purchase set by the Minister for the Economy, the annual volume of electricity that will be purchased from the producers shall equal the estimated electricity sales volume stated by them, and upon exceeding this volume it shall be proportionally reduced.

The producers, planning to launch new combined heat and power production capacities in the coming year, should, before 1 July of the current year, submit their applications regarding volumes of purchased electricity stating the exact date of the start of electricity production.

Pursuant to the volumes of purchase set by the Ministry of the Economy and the Rules for the Regulation of the Price of Electricity Purchase from Combined Heat and Power Producers (hereinafter referred to as the Rules) the National Control Commission for Prices and Energy sets the electricity purchase prices. The prices of electricity purchased from producers are set for the categories of electricity capacities. The electricity price set for an electricity capacity category shall be applied to every producer classified under this category.

The final electricity purchase price is obtained by setting the basic price and adjusting it by the coefficients of capacity and additional investments in new power plants. Both these coefficients are set for three years.

The coefficient evaluating the additional requirement for funds is applied to the power plants of new construction launched after July 2003 and having the nominal power-to-heat capacity ratio of at least 0.45 and the total energy production efficiency (produced energy to used fuel ratio) of at least 75%. Its value, that may not be smaller than 1.1, is set by the Commission.

Purchase and promotion of electricity produced from cogeneration using renewable and waste sources of energy

The Law on Electricity promotes electricity production from renewable energy sources at cogeneration plants but it stipulates certain conditions, i.e. the approved procedure for the purchase of such electricity promotes only the power plants using biomass fuel, which are defined as an energy object generating electricity at combined heat and power production cycle (cogeneration) installations when the nominal power-to-heat capacity ratio of the power plant is at least 0.23 and the amount of biomass and/or biogas used for electricity production is at least 70%.

Electricity production from renewable and waste energy sources at cogeneration plants is a service of public interest and such electricity is purchased at approved tariffs differentiated according to the type of the renewable or waste energy sources used. From 2021 the purchase of electricity generated from renewable and waste energy sources is to be promoted by introducing the system of so-called green certificates without exceeding the specified annual volume of each type of energy.

Electricity production from renewable and waste energy sources at cogeneration plants is also promoted by applying a connection fee discount of 40% to producers; this is regarded as purchase of services in the public interest and operators who have connected power plants to the grid in the coming year are to receive compensation.

Authorisations to the power plants using biomass fuel and the power plants using waste energy sources to expand electricity production capacities are issued in the standard manner prescribed by legislation.

Table 6-1 The maximum volume of production from biomass and waste energy sources subject to the promotion scheme

	Measuring unit	2005	2006	2007	2008	2009
Biomass power plants:						
Planned volume of electricity production	GWh	13.1	39.1	79.1	103.1	127.1
Forecast capacity of power plants at the end of the year	MW	2.3	6.8	18.8	20.8	30.8
Total capacity of planned new power plants	MW	4.5	12	2	10	2
Power plants using solar, geothermal and waste energy sources:						
Planned volume of electricity production	GWh			0.4	1.4	3.2
Forecast capacity of power plants at the end of the year	MW				0.2	0.6
Total capacity of planned new power plants	MW					

Conditions for connecting producers' electrical installations to the operating energy system

The procedure for connecting electric installations to the operating energy system is laid down in Order of the Minister for the Economy of 17 September 2002 (the latest version came into effect on 1 January 2005). Producers' electrical installations are connected to the operator's electrical grid after the producer is issued an authorisation to expand its electricity production capacity and fulfils the conditions and requirements specified in the technical conditions issued by the operator.

Price of the service of connecting producers' electrical installations to the grid equals the estimate value of a connection project. The producers, which generate electricity from renewable and waste energy sources, pay for the service of installation connection pursuant to the Procedure for the Promotion of Production and Purchase of Electricity Generated from Renewable and Waste Energy Sources approved by Resolution No 1474 of the Government of the Republic of Lithuania of 5 December 2001, i.e. they are granted a discount of 40% on the fee. The remaining part of costs is the expenditure on the development of operator grids.

Pricing of electricity transmission and distribution services

Electricity production covers the overall production of electricity at power plants from which this energy is transmitted to high-voltage networks (transmission networks) and to the customers receiving electricity from them, and further from the transmission networks – to the medium- and low-voltage networks (distribution networks), which distribute electricity to individual customers according on the level of voltage they receive electricity from. Ancillary services are necessary to maintain voltage and frequency within the set limits, the required reserve of capacity and energy resources, and ensure the established level of electricity supply quality and reliability. Supply means the activity related to electricity suppliers' work with customers and other market participants. These functions are executed by different enterprises and therefore there arises the necessity to distribute costs and calculate prices according to these technological stages.

Pursuant to the applicable procedure the limits of the price cap for electricity transmission service and distribution service, based on economic principles, are set for three years, i.e. the initial level of the relevant activity income is set for three years and the price cap is recalculated every year considering the adjustment coefficient by creating possibilities for enterprises, during that time, to reduce costs and receive more profit than approved by the Commission.

Consumers pay for electricity according to the prices of electricity production and of the services of public (independent) supply, transmission, including ancillary services, and distribution within medium-voltage networks and distribution within low-voltage networks depending on the voltage of the network from which they receive electricity.

6.2 Heat sector

The heat sector is additionally regulated by the Law on Heat Sector adopted by the Seimas of the Republic of Lithuania on 20 May 2003. Currently the Seimas holds discussions on amending this Law.

The Law on Heat Sector regulates state management of the heat sector, the activities of the heat sector entities and their relations with heat customers and responsibilities.

The main objectives of the Law:

to ensure reliable and high quality supply of heat to heat customers at minimum costs;

to ensure by law effective competition in the heat sector;

to defend the rights and legitimate interests of heat customers;

to increase the efficiency of heat production, transmission and consumption;

when producing heat, to increase the use of local fuel, biofuel and renewable energy sources;

to reduce the negative impact of the heat sector on the environment.

Pursuant to the Law on Heat Sector the State (municipalities) shall promote purchase by heat supply systems of heat produced from biofuel, renewable sources of energy, waste incineration and geothermal energy sources. The purchase of such heat is an obligation of utility enterprises. Heat suppliers must purchase heat from independent heat suppliers if it is generated from renewable sources or by using the combined heat and power production technology. The only exception is possible if the purchased heat increases the total heat production costs.

The Law on Heat Sector lays down the main provisions related to combined heat and power production, i.e. cogeneration:

1. Combined heat and power production (cogeneration) is a service of public interest. The Government or an institution authorised by it shall set the scope of and the purchase for the purchase of electricity from co-generators of heat and power taking regard of the necessity to efficiently use the electricity and heat production capacities.

2. A heat supplier should hold licences. The enterprise supplying annually not less than 5 GWh of heat shall be issued heat supply licences by the National Control Commission for Prices and Energy. The issued licences shall be open-ended.

3. Investment projects shall be coordinated in accordance with the procedure established by the National Control Commission for Prices and Energy.

4. Heat prices (tariffs) shall be regulated by the National Control Commission for Prices and Energy. A tariff shall be set for at least 3 years, and for the maximum period of 5 years, with the possibility of changing it if the price of the fuel component sharply changes.

Heat purchase from cogeneration plants

Heat purchase from cogeneration plants is regulated by the Procedure for the Purchase by Heat Supply Systems of Heat from Independent Producers. If the tender price of heat of all independent producers is the same, the supplier shall purchase heat from independent heat producers' installations in the following order of priority:

1. heat from combined heat and power production installations using renewable sources of energy;
2. heat produced from renewable and geothermal sources of energy;
3. waste heat from industrial enterprises;
4. heat from high efficiency cogeneration units;
5. heat from fossil organic fuel boiler-houses.

6.3 Fuel sector

Gas sector

The gas sector is additionally regulated by the Law on Natural Gas adopted by the Seimas of the Republic of Lithuania on 10 October 2000, and its latest version was adopted on 28 January 2003. Currently amendment to the law on Natural Gas is under discussion.

This Law establishes the general organisation principles of the natural gas sector and the operations of natural gas enterprises and relations with the customers (in the supply, distribution, transmission and storage of natural gas).

The Law lays down the provisions related to combined heat and power production (cogeneration plants):

1. Relations of gas enterprises with customers and system users shall be based on contracts.

2. Gas enterprises shall have the right to supply gas to the eligible customers through direct pipelines. The eligible customers shall have the right to obtain gas supplied through direct pipelines. The Government of the Republic of Lithuania or the institutions authorised by it shall set the terms of

direct pipeline installation and the terms of issuing the licences to install them. Regulated customers shall be supplied with gas by the distribution enterprise. Pursuant to Order of the Minister for the Economy of 1 January 2004 the following users shall be recognised as the eligible customers:

a) power plants;
b) customers, who consume over 1 million cubic metres of gas annually;
c) customers whose systems have direct access to the main gas pipelines;
d) distribution enterprises whose systems have direct access to the main gas pipelines.

3. The prices of transmission, distribution, storage and the gas prices for regulated customers shall be regulated in the gas sector.

4. A gas enterprise may refuse access to use the system, on the basis of lack of capacity, or where the enterprise could not implement the obligations assigned to it by the Government or an institution authorised by it. Refusal of access to the system must be objective, non-discriminatory and reasonable.

5. The transmission or distribution enterprises must, in response to requests by customers or other gas enterprises, enhance the capacity of the system or construct a new gas pipeline, should that be economically justifiable or should the requester assume the obligation of funding the costs of enhancing the capacity of the system inasmuch as they exceed the economically justifiable costs of enhancement of the capacity of the system. The issues concerning enhancement of the capacity of the system and construction of new pipelines shall be resolved through an agreement among the parties.

Renewable sources

The legal framework for the production and use of biofuel, biofuels for transport and bio-oils is regulated by the Law on Biofuel, Biofuels for Transport and Bio-oils.

The main objectives of the Law are:

1. to reduce the dependence of the national energy sector on fuels produced from mineral resources and imported raw materials;

2. to increase the efficient use of indigenous, renewable and alternative energy resources and the security energy supply;

3. to reduce greenhouse gas and pollution emission levels.

Biofuel production from raw materials of Lithuanian origin is carried out under the programmes approved by the Government and financed from the State budget, and its producers and users are granted preferences provided for by the law. Biofuel production is equated to the development of new environment-friendly technologies using renewable sources of energy. By means of a Government resolution, such activities may be granted the status of a pilot project.

The Programme for the Promotion of the Production and Use of Biofuels in 2004-2010 was approved on 26 August 2004.

Pursuant to the Law on Excise Duty of the Republic of Lithuania the excise duty is not applied to electricity generated from renewable sources of energy. The excise preferences are applicable to the share of biofuel corresponding to the share of additives of biological origin (in %) in a product tonne.

6.4 Conclusions and recommendations

After analysing the legislation regulating combined heat and power production, it can be stated that no artificial administrative barriers to combined heat and power production are created and the system for its promotion and support is developed in the country. Combined heat and power production is supported through the system of quotas by treating electricity produced at cogeneration plants according to the quotas as a matter of public interest. Such electricity is purchased at the prices set by the Government. When cogeneration plants use biomass for fuel and if the power plants meet the criteria specified in the procedure for the purchase of such electricity, electricity produced at them is purchased at the set prices for electricity generated from renewable sources of energy. Additional support to such power plants is granted by applying a discount of 40% on the fee for connection to the energy system.

The current system provides quite favourable conditions for the construction of new cogeneration plants. Yet, from the standpoint of the producer and investor certain shortcomings of the system should be pointed out:

- When developing their investment business plans enterprises should estimate the scope and the forecast prices of electricity sales realistically and precisely. Financing institutions and a project developer estimate the potential proceeds for at least 10-15 years. Cogeneration plant project preparation and implementation takes from 2 to 3 years. However, pursuant to the currently applicable procedure (the Procedure for Purchasing Electricity from Co-generators of Heat and Power of 30 June 2003), the quota volume of electricity sales of a particular cogeneration plant is announced only a half-year before the beginning of production. Without having advance detailed information on the future volume of purchase, considerable uncertainty occurs when calculating return on investment and estimating additional risk.

- When approving electricity purchase prices the Commission on Prices applies the coefficient of additional expenses no smaller than 1.1 with regard to new cogeneration plant for three years; however, its particular value is set by the Commission on Prices without applying any clear assessment criteria. This again creates uncertainty when forecasting project cash flows.

- Pursuant to the currently applicable procedure for the connection of electricity producers to the existing system, the connection fee is equal to the full value of the connection project, which is set by the operator of an electricity network. In other words, the producer connects to the existing system at its own expense in accordance with the technical conditions issued by the operator. The time-limit of issuing the technical conditions is not regulated. Connection to the point specified in the contract is organised by the operator. Such a procedure and payment terms considerably increase the construction costs of a new power plant and extends the duration of project implementation. The producer (investor) has very limited possibilities to influence this process both in terms of the implementation duration and the price.

- Pursuant to the applicable pricing the transmission costs represent nearly half of the price of electricity to the final customer. For this reason and due to a high connection fee construction of cogeneration plants, satisfying their own electricity requirements, in district DH enterprises has gained in popularity in the recent years, which reduces the potential of high-efficiency combined heat and power production based on the useful heat demand.

Recommended amendments to legislation relating to the application of Directive 2004/8/EC:

1. It is proposed that the Procedure for Purchasing Electricity from Co-generators of Heat and Power be amended by adding a provision enabling enterprises which plan to construct a new cogeneration

plant to find out earlier than before the half-year the share of the quota of electricity they can expect to be granted or reserve. Thus, entities planning to produce electricity would clearly know the proportion by which the purchase of electricity produced by them would be reduced in line with services of public interest in the particular year. To secure a reservation, the enterprise should present a business plan, the economic and financial indicators proving the enterprise's financial capacity to implement the project and a bank (insurance) guarantee.

2. It is proposed that the Rules for the Regulation of the Price of Electricity Purchased from Combined Heat and Power Producers (paragraph 6) also specify the upper limit of the coefficient evaluating the requirement for additional funds for the construction of new power plants as well as the clear criteria of establishing (increasing) it.

3. It is proposed that the Procedure for Purchasing Electricity from Co-generators of Heat and Power (Order No 4-262 of the Minister for the Economy) be amended by adding a provision stating that producers should furnish the Ministry of the Economy, before 1 July of the current year, with applications for electricity purchase for the next year by specifying not only the design power and heat capacities of cogeneration units but also a certificate regarding the actual power-to-heat ratio based on useful heat metering, issued by a competent authority (that is related neither to energy production nor to transmission activities). The useful heat should be evaluated according to the principle that heat losses in its transmission system (pipelines) are the same as those of heat produced in units other than cogeneration units.

4. Considering the promotion of, and support to, high-efficiency cogeneration plants under Directive 2004/8/EC, it is proposed that the Procedure for Purchasing Electricity from Co-generators of Heat and Power be amended by adding a provision stating that electricity produced in cogeneration units can be treated as a service of public interest if the amount of electricity produced meets the criteria for high-efficiency cogeneration, i.e. allows primary energy savings of at least 10% compared with the separate production of heat and power (according to generally approved reference values).

5. It is proposed that a discount be applied to the fee for connection to the existing electricity systems to high-efficiency cogeneration plants similar to that applicable to the producers generating electricity from renewable and local sources of energy.

6. Pursuant to Article 5 of Directive 2004/8/EC, a legal act laying down the procedure for issuing the guarantees of origin of electricity produced from high-efficiency cogeneration should be adopted.

7. Pursuant to Directive 2004/8/EC, the methodology for the calculation of the amount of electricity from cogeneration and the methodology for determining the efficiency of electricity production from cogeneration should be approved.

8. The EU Guidelines on the implementation of Directive 2004/8/EC recommend using document CWA 45547 "Manual for Determination of Combined Heat and Power (CHP)" worked out by the European standardisation organisation CEN/CENELEC. It is proposed that this document be adopted in Lithuania as well.

8 Proposals and provisions for inclusion in the National Energy Strategy

This chapter presents proposals regarding the transposition of the provisions of European Union Directive 2004/8/EC into the National Energy Strategy.

With the aim of transposing the provisions of EU Directive 2004/8/EC into the National Energy Strategy, the following statements should be added to the Strategy:

- The performed analysis of the technical and economically justifiable high-efficiency potentials shows that in 2004 Lithuania produced around 3.2 TWh or 16.4% of electricity that can be classified as electricity from cogeneration according to Directive 2004/8/EC. Subject to the harmonised thermal and electric efficiencies of separate heat and power production, approved at the beginning of the next year, and the amount of electricity produced at the operating high-efficiency cogeneration units (from 2004, 12 TWh of the internal electricity demand), the technical potential accounts for 49% and the economically justifiable potential accounts for 39%. Therefore, in order to achieve the internal demand for electricity of 35% (forecast for the year 2020) or 15.5 TWh produced at cogeneration plants in 2020, the amount of electricity produced at high-efficiency cogeneration units have to be enhanced by: 1.1 TWh until 2010, 1.3 (TWh) until 2015 and 1.3 (TWh) until 2020.
  Note: when the electric efficiency of separate heat and power production accounts for 50%; taking account of the fact that the existing units produce 1.8 TWh of electricity in a high-efficiency cogeneration process.

- It is proposed that the National Energy Strategy specify the beginning of construction of the cogeneration installations using natural gas in Klaip•da, Šiauliai, Panev•žys (Unit 2) and Mažeikiai, on condition that natural gas supply is ensured, no later than until 2009. After the closure of Ignalina NPP, the cogeneration plants constructed in these cities could produce around 0.7-1.2 TWh of electricity per year.

- On the basis of Article 5, it is proposed that the operator of the electricity transmission system be authorised to issue guarantees of origin for electricity from combined heat and power production according to the developed non-discriminatory and transparent mechanism for issuing guarantees of origin.

- On the basis of Articles 5, 6, 9, 11 and 13, it is proposed that an information system be developed enabling the collection and storage of extensive technical data about the country's cogeneration plants (installed capacity, etc.), the types of fuel used and the main amounts of high-efficiency combined heat and power production. This information system would be the first step towards the creation of a momentary (hourly) electricity market, which should become effective on 31 December 2009, by ensuring non-discriminatory and transparent actions of all market participants.

- On the basis of Articles 6, 9, 11 and 13, it is proposed that the National Control Commission for Prices and Energy be instructed to approve only such investment projects relating to the development of electricity production capacities (or investment in operating units) that, according to an economic evaluation of the envisaged activities, demonstrate the expediency of the envisaged investment not only in terms of a business (financial) assessment but also from the national standpoint, covering the avoidance of cross investments in heat and power production units, appropriate utilisation of the available heat demand for technological development and enhancement of energy sector efficiency.

- On the basis of Article 7, it is proposed to promote (through a quota mechanism, state guarantees, etc.) only electricity production that is based on the useful heat demand and only if the amount of energy produced meets the criteria of high-efficiency cogeneration, i.e. allows primary energy savings of at least 10% compared with separate heat and power production (according to generally approved reference values). It is proposed that the share of electricity generated in a process other than high-efficiency cogeneration should not be promoted.