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An analysis of the legal and market framework for the cogeneration sector in Croatia

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ABSTRACT

Following a strategic orientation towards sustainable development, the Government of the Republic of Croatia has changed its energy legislation and has put forward a framework for the systematic development and increased use of renewable energy sources and cogeneration. This paper focuses on changes in the regulatory context relevant to the cogeneration sector and also analyses the impact of energy market transition on cogeneration viability in municipal district heating, industry, services and the residential sector. Particular attention has been paid to the expected changes of heat, electricity and gas prices. We present a simple model for quantitative prediction of the cogeneration system profitability at different power levels under given national circumstances. Our findings support a need for a strong institutional support for initial penetration of the micro-cogeneration technologies into the Croatian energy system.

1. Introduction

Cogeneration, or combined heat and power (CHP) production, attracts increased attention throughout the world as one of the most appropriate concepts for achieving the goals of energy efficiency and energy conservation. However, a share of cogeneration in global power generation is still relatively small and amounts to approximately 9% [1]. An additional policy effort is needed in many countries to overcome existing barriers and to strengthen the position of cogeneration in the liberalized energy markets.

European Union (EU) started a process of regulatory changes in 1997 [2] with the aim to double the cogeneration share in power generation from 9% to 18% by 2010. Although the amount of electricity generated in cogeneration plants increased in the majority of EU countries, the increase of the cogeneration share was slower than expected. In the year 2005 the cogeneration share in total power generation in EU-27 was 11.1% being higher in the new Member States (16.7%) than in the pre-2004 EU-15 where it was 10.2% [3]. The development of the Cogeneration sector in many EU countries was affected by the unfavourable market conditions and by uncertain and changing regulatory environments aroused from electricity market liberalization [4,5]. In 2004, the EU Commission recognized the weak cogeneration position and adopted a Directive on the promotion of high-efficiency cogeneration [6]. The objective of the Cogeneration Directive and related acts [7,8] is to establish a common framework to promote and facilitate the installation of cogeneration plants where demand for useful heat exists or is anticipated.

Further development of the cogeneration sector in Croatia also relies on the establishment and the successful implementation of a favourable legislative framework [9–11]. During the last decade, utility and industrial cogeneration plants in Croatia supplied 11–16% of the electricity market and more than 70% of the heat required in the district heating systems or industrial processes. The installed electrical capacity is bigger than 700 MW_e. The existing applications are based on steam turbines, gas turbines (GT) and gas engines in the size range from 1.6 to 210 MW_e [12]. Potential for further expansion of cogeneration exists especially in the residential and commercial sector where the largest portion of the heat demand is covered by heating-only boilers. The increase of CHP electricity production is possible at different power levels, ranging from several kW_e to more than 100 MW_e.

The utilization of the existing CHP potential could be influenced by the tariff system and other means of energy policy by increasing the investment security while securing that cogeneration operates in high-efficiency mode. The final effect of implemented policy means depends on the actual conditions on the energy market (especially on the fuel and electricity prices, respectively), as well as on the operational characteristics and the investment costs of various cogeneration technologies. Forecasting of this effect in a given energy system is possible by taking into account all relevant influencing parameters. The aim of

Abbreviations: CC, combined cycles; FC, fuel cells; GT, gas turbines; HV, high voltage; ICE, internal combustion engines; LV, low voltage; MICE, micro internal combustion engines; MGT, micro gas turbines; MV, medium voltage; SE, Stirling engines

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Nomenclature

Symbols

C	power-to-heat ratio (–)
c	specific costs (EUR/kW, EUR/kWh)
CRF	capital recovery factor (–)
E	electricity (kWh)
F	fuel (kWh)
H	heat (kWh)
I	investment (EUR)
i	discount rate (%)
LF	load factor (h/a)
n	economic life time (a)
P	plant nominal power (kW, MW)
η	efficiency (%)

Subscripts

A	annual
CHP	combined heat and power
E	electricity
e	electricity
H	heat
I	investment
O	overall
OM	operation and maintenance
Ref	reference

any support system in cogeneration must be to increase efficiency of energy production, while in the same time removing barriers to higher penetration of more efficient technologies, avoiding hidden subsidies and support system abuse. In order to avoid producing only electricity for sale while dumping or not producing heat, the tariff must be designed in a way that it is financially neutral regarding exporting and importing electricity to and from the grid.

In this paper, a simple model is proposed which renders a quantitative analysis of the viability of the investment into a cogeneration plant at different power levels under given conditions of energy markets and given institutional measures. In distinction to various approaches focusing on calculation of economic viability of particular case [13–15], the proposed model provides an integral view of the attractiveness of different cogeneration technologies in a typical national framework.

By the use of the proposed model and by the analysis of respective administrative procedures, it is shown that a strong institutional support is needed for initial penetration of the micro-cogeneration technologies into the Croatian energy system, possibly through an obligation system, while small to large cogeneration systems may be efficiently supported through feed-in tariff approach.

2. Energy sector reforms in Croatia

Currently the Croatian energy sector is undergoing transformation. Since Croatia is an EU candidate, energy sector reforms are largely influenced by the relevant EU directives. Reforms of the energy sector in Croatia started in the year 2001 when a package of the five energy-related acts (Energy Act, Electricity Market Act, Gas Market Act, Oil and Oil Derivatives Market Act, Regulation of Energy Activities Act) came into force. In the period that followed, the Croatian Government was not satisfied with the progress made towards accomplishing the reform goals and initiated revision of the legislation that regulates the energy sector. The latest revised version of energy-related acts was adopted in 2007 [16–20].

The Energy Act includes provisions concerning energy policy and energy development planning, national energy programs, energy efficiency and renewable energy sources, performing energy-related activities, electricity market and public services, energy prices, conditions of energy supply, administrative and inspection supervision.

The Electricity Market Act prescribes dynamics of electricity market liberalization. There are two groups of customers in Croatia: eligible and tariff customers. Since July 2008, all customers are deemed eligible customers and can choose a supplier on a free market and negotiate the electricity price. The Electricity Market Act also introduces the concept of a privileged producer, a status that can be obtained by a producer which simultaneously produces electricity and heat in an individual generation facility or utilises waste or renewable energy sources in an economical way while taking into account measures of environmental protection.

The organization of the electricity market, electricity transmission and distribution are regulated activities performed as public services. Responsibilities are shared amongst a number of independent regulatory bodies such as Croatian Energy Regulatory Agency (CERA), Market Operator, Transmission System Operator (TSO) and Distribution System Operator (DSO), together with the Ministry of Economy, Labour and Entrepreneurship (MoELE).

The revised version of the Gas Market Act establishes the institutional system relating to the supervision of the security of gas supply and prescribes regulated access of third parties to the gas transport, distribution and storage system. A privileged status can be achieved by customers who wish to buy gas for the purpose of generating electricity regardless of their annual consumption, those buying gas for simultaneous production of electricity and heat (combined heat and power producers) regardless of their annual consumption, those buying gas exclusively for their own needs whose annual consumption exceeds 25 million m^3 of gas, and those buying gas for steel production. Until the year 2011, the Government of the Republic of Croatia could, for a certain period of time, limit the price of gas for privileged customers.

Considerations linked to Croatia's expected obligations under Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal electricity market, as well as Croatia's commitment to the Kyoto Protocol, have inclined policy makers to increase renewable energy share in electricity consumption mainly through supporting new energy sources like wind, solar and biomass. As far as the cogeneration sector is concerned, the adopted legislation changes follow the objectives of Directive 2004/8/EC. The efforts have been focused on consolidation of existing cogeneration installations and on the establishment of a supportive environment for new plants installation.

The objectives of Croatia's energy sector reforms are similar to other national policies [21–25] and are not strictly energy related. Besides the issues such as: "security of energy supply", "encouraging the competition", "improving the efficiency and management transparency of the energy sector", the objectives also include more general national goals such as: "domestic industry development", "import decrease", "employment increase" and similar. Some of these policy goals may sometimes be in conflict with the liberalization of the energy market and therefore it might be necessary to implement financial mechanisms that will support development of cogeneration sector.

There are also other challenges imposed by global and local circumstances such as: further adoption and implementation of EC directives, useful heat monitoring issues, expected development of small-scale cogeneration in tertiary sector, expected establishment of green certificates, operation in regional electricity market, increased fuel prices, increased penetration of wind electricity and biomass market establishment.

3. Cogeneration legislation

Following the provisions of the Energy Act and Electricity Market Act, a secondary regulation common for cogeneration and renewable energy sources was adopted in the first half of the year 2007. The adopted secondary regulation package consists of following documents:

- Regulation on the minimum share of electricity produced from renewable energy sources and cogeneration in the electricity supply [26].
- Tariff system for the production of electricity from renewable energy sources and cogeneration [27].
- Regulation on the fee for the promotion of the electricity production from renewable energy sources and cogeneration [28].
- Ordinance on the usage of renewable energy sources and cogeneration [29].
- Ordinance on obtaining the eligible electricity producer status [30].

3.1. Licensing procedure

The licensing procedure for obtaining a privileged producer status consists of a series of steps which are prescribed in primary and secondary regulation dealing with physical planning, construction, energy, forestry and state property management. Prior to any application, potential investors have to be registered for electricity generation. The licensing procedure starts with prior authorisation issued by Ministry of Economy, Labour and Entrepreneurship (MoELE). The next step is a study of the environmental impact which will be evaluated by a commission formed by state government or local self-government bodies. If the plant is judged environmentally suitable, potential investors are able to apply for a location permit. The permit may be issued by the county office in charge of physical planning or, if the proposed installed power is estimated to exceed 20 MW, by the Ministry of Environmental Protection, Physical Planning and Construction (MoEPPPC). The provisional connection authorisation issued by transmission/or distribution system operator (TSO/DSO) is required for location permit. At the next level of the authorisation procedure investors will apply to the same institutions for a building permit (issued by MoEPPPC or county offices, depending on the plant size), a connection contract (issued by TSO/DSO) and a connection authorisation (TSO/DSO). The building permit is a precondition for obtaining the final authorisation (issued by MoELE) and the prior decree on the privileged producer status (issued by CERA). At this stage the applicant also signs a contract on grid usage with TSO/DSO and a contract for purchasing electricity with the market operator. After the building and the commissioning phase, a trial run is a precondition for obtaining the operation/use permit (issued by MoEPPPC or county offices). The final decree on privileged producer status is issued by CERA. The last step in the licensing procedure is signing the electricity purchase contract with the Market Operator, which is valid for 12 years. A simplified illustration of the licensing procedure has been presented in Fig. 1. Although complex in some parts and despite the considerable administration involved, the described procedure assures a non-discriminatory and transparent framework for cogeneration systems licensing.

It is expected that average time required for the entire procedure could be between $1\frac{1}{2}$ and 3 years. Since legislative framework has been working only for 1 year and none of the new projects have up to now passed the procedure entirely it is impossible to give more precise estimate.

3.2. Primary energy savings criterion

In addition to the described procedure, cogeneration systems have to confirm a privileged producer status each year by fulfilling primary energy savings criterion. The criterion has been introduced in line with the Cogeneration Directive and according to the harmonized matrix of efficiency reference values for separate production of electricity and heat [7,8].

The calculation of primary energy savings (*PES*) for a chosen cogeneration plant is based on the annual production of heat and electricity and consumption of primary fuel. The primary energy savings are defined using

$$PES = \left(1 - \frac{1}{\eta_{CHP\text{-}H}/\eta_{Ref\text{-}H} + \eta_{CHP\text{-}E}/\eta_{Ref\text{-}E}}\right)100\% \tag{1}$$

PES denotes the primary energy savings provided by cogeneration production. *PES* has to be greater than 10% for systems bigger than 1 MW_e, while for smaller systems *PES* has to be positive. The cogeneration system fulfilling *PES* criteria is called "high-efficiency cogeneration" and could obtain or hold the status of privileged producer.

The efficiency of the cogeneration plant's heat production $\eta_{CHP\text{-}H}$ is defined as annual heat output divided by the annual fuel input, while $\eta_{Ref\text{-}H}$ is the efficiency reference value for separate heat production. The efficiency of the cogeneration plant's electricity production $\eta_{CHP\text{-}E}$ is defined as annual electricity from cogeneration divided by the annual fuel input while $\eta_{Ref\text{-}E}$ is the efficiency reference value for separate electricity production.

Reference values have been differentiated by year of construction and types of fuel and are corrected by factors relating to average climatic conditions and avoided grid losses. The highest efficiency reference values are valid for the newest natural gas-fired plant: for separate electricity production $\eta_{Ref\text{-}E} = 52.5\%$ and for separate heat production $\eta_{Ref\text{-}H} = 90\%$.

Prior to calculation of the primary energy savings, all cogeneration systems have to check whether overall efficiency, calculated as the ratio of annual energy output (summarized heat and electricity outputs) and annual fuel consumption, is at least 75% (for most of the systems) or at least 80% (for systems based on combined-cycles (CC) gas turbines or on steam condensing extraction turbines). If the cogeneration system passes the overall efficiency test, total annual electricity production of the plant is considered as cogeneration electricity. Otherwise, the annual plant data should be separated to production in cogeneration and non-cogeneration mode. The amount of electricity produced in cogeneration mode, E_{CHP} is either measured or calculated using

$$E_{CHP} = CH_{CHP} \tag{2}$$

where H_{CHP} is the amount of useful heat from cogeneration (calculated as total heat production minus any heat produced in

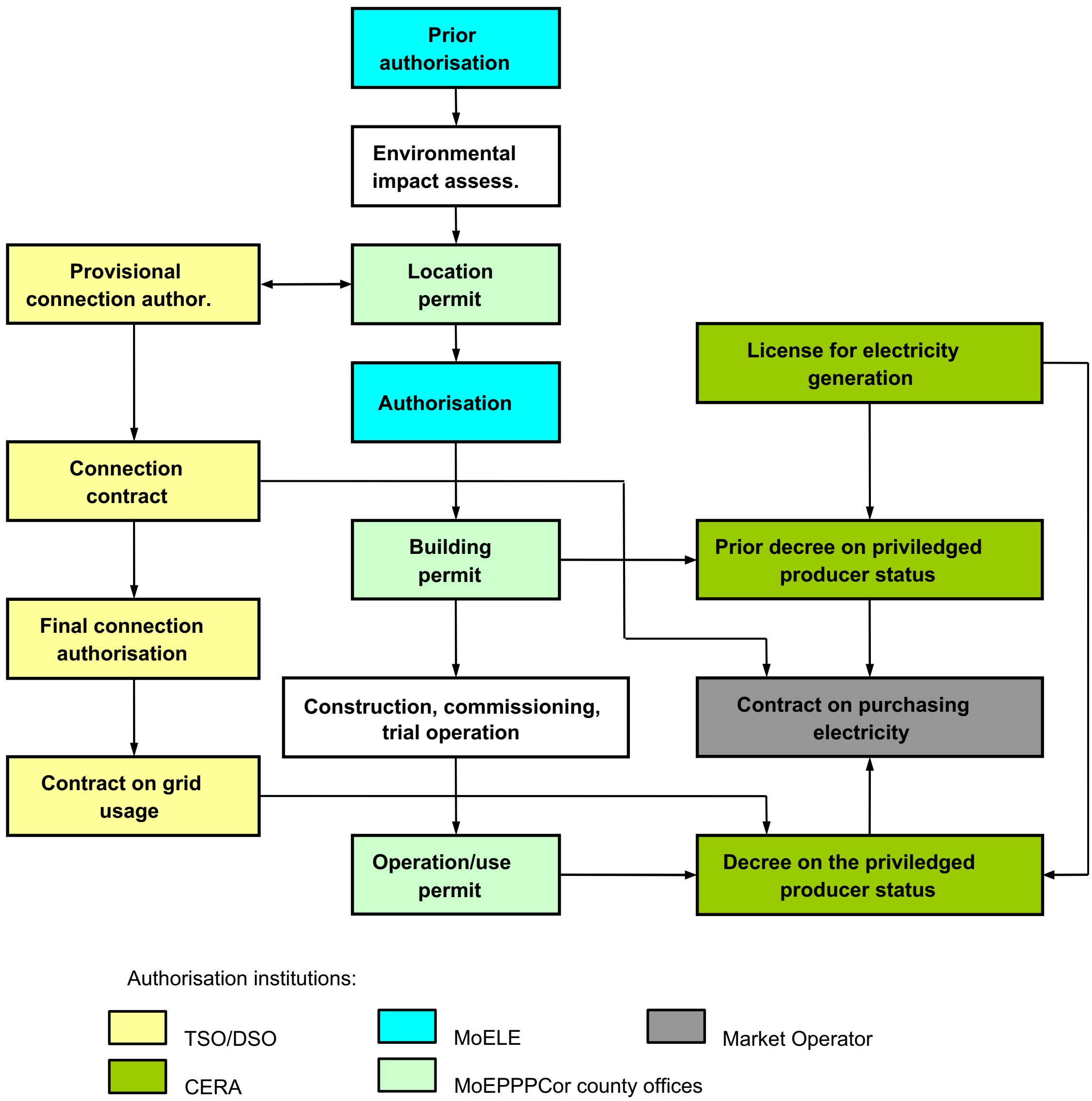

Fig. 1. Simplified illustration of licensing procedure.

separate boilers or by live steam extraction from steam generator before the turbine) and C is the power-to-heat ratio defined for different cogeneration technologies (0.95 for combined-cycle gas turbine with heat recovery, 0.45 for steam backpressure turbine and for steam condensing extraction turbine, 0.55 for gas turbine with heat recovery, 0.75 for internal combustion engine (ICE)).

The alternative approaches for high-efficiency cogeneration assessment are still in force in several countries as described in [31]. There is also discussion on the pertinence of the methodology proposed in EU Cogeneration Directive [32].

3.3. *Feed-in tariffs*

The adopted tariff system is similar to the net metering system and comprises elements of the avoided costs model. Feed-in tariffs are determined with respect to plant size and connection voltage level, peak and off-peak generation periods as shown in Table 1.

Correction of the feed-in tariffs has also been introduced in order to protect CHP producers from market fluctuations of gas and electricity prices.

There is no specific incentive for installation and operation of biomass-fired CHP systems. Biomass electricity-only and biomass CHP systems have the same status in national support system. The feed-in tariff for biomass-fired installations lay between 11 and 16 c€/kWh. The biomass support system implementation might initiate production of more renewable electricity but not in the most efficient way.

4. Economic assessments

Putting aside sometimes complex administrative procedures, the main factor determining the attractiveness of cogeneration project is its profitability which is influenced mostly by

- fuel, electricity and heat prices,
- capital and maintenance costs,
- plant design and operation criteria.

Energy prices in Croatia are rather low when compared to European averages. Government administration is in a position to partially influence the formation of the energy prices and this

Table 1
Feed-in tariffs for electricity delivered from cogeneration plants with a status of privileged producer in c€/kWh, (1 €~7.3 HRK).

	Peak 7:00–21:00 (winter time) 8:00–22:00 (summer time)	Off-peak 21:00–7:00 (winter time) 22:00–8:00 (summer time)
Cogeneration plants with installed power up to and including 50 kW, so-called micro-cogeneration and all cogeneration plants that use hydrogen fuel cells	8.36	4.38
Cogeneration plants with installed power over 50 kW, up to and including 1 MW, so-called small cogeneration	6.99	3.56
Cogeneration plants with installed power of over 1 MW up to and including 35 MW, so-called medium cogeneration, connected to the distribution network	6.03	3.01
Cogeneration plants with installed power of over 35 MW, so-called large cogeneration, and all cogeneration plants connected to transmission network	4.11	2.05

position has been regularly used for customer protection. Capital, operation and maintenance costs are determined by type and size of implemented cogeneration technology while plant operation criteria are usually related to heat demand profile at the chosen site.

In this work the evaluation of the economic prospects of relevant cogeneration technologies has been performed based on comparison of electricity generation costs with electricity purchase prices and feed-in tariffs.

4.1. Methodology

The model, based on annuity method, has been proposed for the estimation of the electricity generation costs c_E:

$$c_E = \frac{I_A + c_{OM}E_{CHP} + c_F F_{CHP} - c_H H_{CHP}}{E_{CHP}} \tag{3}$$

where I_A denotes annualized capital costs, c_{OM} specific operation and maintenance costs, c_F fuel costs, E_{CHP} annual electricity generation, F_{CHP} annual fuel consumption, H_{CHP} annual heat supplied and c_H heat price. The formula (3) is based on the assumptions that the product $c_H H_{CHP}$ represents revenue and that the entire investment, operating and maintenance costs are allocated on the electric output. c_H represents either a market price of heat (in case the cogenerated heat replaces heat purchased from district heating network) or avoided cost of heat generation in auxiliary boiler (in case the cogenerated heat is consumed locally).

By substituting I_A, E_{CHP}, F_{CHP} and H_{CHP} with the following equations:

$$I_A = I\,CRF = c_I P \frac{(1+i)^n i}{(1+i)^n - 1} \tag{4a}$$

$$E_{CHP} = LF\,P \tag{4b}$$

$$F_{CHP} = \frac{E_{CHP}}{\eta_{CHP\text{-}E}} = \frac{LF\,P}{\eta_{CHP\text{-}E}} \tag{4c}$$

$$H_{CHP} = F_{CHP}\eta_{CHP\text{-}H} = LF\,P\left(\frac{\eta_{CHP\text{-}O}}{\eta_{CHP\text{-}E}} - 1\right) \tag{4d}$$

the expression (3) could be transformed to

$$c_E = \frac{c_I}{LF}\frac{(1+i)^n i}{(1+i)^n - 1} + c_{OM} + \frac{c_F}{\eta_{CHP\text{-}E}} - c_H\left(\frac{\eta_{CHP\text{-}O}}{\eta_{CHP\text{-}E}} - 1\right) \tag{5}$$

where c_I denotes specific investment cost, P denotes nominal power of cogeneration plant while LF denotes annual load factor. The capital recovery factor CRF is calculated in dependence on discount rate i and the economic life time n.

The expression (5) models how electricity generation costs depend on technology parameters c_I, c_{OM}, $\eta_{CHP\text{-}E}$, $\eta_{CHP\text{-}O}$ and on parameters c_I, c_{OM}, n, i, LF describing specific economic, market and site conditions.

4.2. Input data

Costs and performance data of various cogeneration technologies relevant for existing and future applications are presented in Table 2 [33–39]. The economic life time of 12 years has been chosen in line with the validity of the electricity purchase contract. The discount rate of 7% has been chosen for all examined systems based on realistic Croatian framework conditions.

Table 2
Characteristics of cogeneration technologies [33–39].

P (kW_e, MW_e)	c_I (€/kW)	c_{OM} (c€/kWh)	$\eta_{CHP\text{-}E}$ (%)	$\eta_{CHP\text{-}O}$ (%)
Micro internal combustion engines (MICE)				
1 kW_e	7000	1.2	21.3	85.0
4.7 kW_e	2500	1.2	25.0	90.0
5.5 kW_e	2360	1.2	27.0	90.0
10 kW_e	2150	1.1	28.1	85.0
20 kW_e	1230	1.1	37.4	87.4
30 kW_e	1000	1.1	33.1	84.3
Stirling engines (SE)				
1 kW_e	9000	1	12.0	92.0
9.5 kW_e	2600	1	26.0	98.0
Micro gas turbines (MGT)				
30 kW_e	2028	1.5	25.5	74.4
70 kW_e	1482	1.2	27.8	67.7
80 kW_e	1486	1	26.6	69.9
100 kW_e	1361	1.2	28.7	68.8
Fuel cells (FC)				
8 kW_e	4231	2.5	33.3	76.6
200 kW_e	4000	2.2	40.0	79.9
250 kW_e	3846	3.3	47.7	72.2
2000 kW_e	2500	2.5	51.1	77.7
Internal combustion engines (ICE)				
100 kW_e	1038	1.4	33.0	86.6
300 kW_e	892	1	34.0	85.5
1 MW_e	727	0.7	38.0	78.8
3 MW_e	719	0.7	39.0	76.6
5 MW_e	685	0.6	41.0	81.3
Gas turbines (GT)				
1 MW_e	1469	0.8	24.3	72.2
5 MW_e	788	0.5	30.1	74.4
10 MW_e	714	0.5	32.2	76.6
25 MW_e	615	0.4	38.0	77.7
40 MW_e	540	0.3	41.0	79.9
Combined cycles (CC)				
35 MW_e	662	0.4	47.0	90.0
75 MW_e	592	0.4	49.5	90.0
100 MW_e	462	0.4	53.0	90.0

All energy prices used are related to the statistics data collected for the year 2006 [12].

In 2006, average purchase prices for electricity in Republic of Croatia were 4.26 c€/kWh for consumers connected to the high voltage (HV) (transmission) network, 6.19 c€/kWh for consumers connected to the medium voltage (MV) network, 8.14 c€/kWh for the enterprises connected to the low voltage (LV) network. Average electricity price for households was 7.95 c€/kWh.

Less than 70% of the electricity costs paid by the industrial and commercial consumers are costs of the energy consumed, while more than 30% are caused by connection capacity fee, administrative and system charges which can be completely avoided by electricity generated on site.

Average gas price for industrial consumers in 2006 was 6.89 €/GJ (2.48 c€/kWh) while the average gas price for household was 8.18 €/GJ (2.94 c€/kWh). Several bigger industrial and utility consumers had a lower purchase prices under conditions of take-or-pay natural gas supply contracts.

Heat purchase prices were in the range of 2.5 c€/kWh, for customers connected to the big district heating systems, to 5.4 c€/kWh for customers connected to the small heating networks.

4.3. Results

The electricity generation prices have been calculated based on input data from Section 4.2 and expression (5). In the calculations an annual load factor of 4000 h has been used and a heat price 20% higher than the respective fuel price has been assumed (representing an approximate average of values given in [40,41]). The calculated results for different cogeneration technologies and for capacity ranges defined in tariff system have been presented in Figs. 2–5.

The comparison of the calculated electricity generation costs shows that costs generally decrease with increasing plant capacities. The illustrations also show that some cogeneration technologies, such as Stirling engines (SE), fuel cells (FC) and micro gas turbines (MGT) are still significantly more expensive than internal combustion engines.

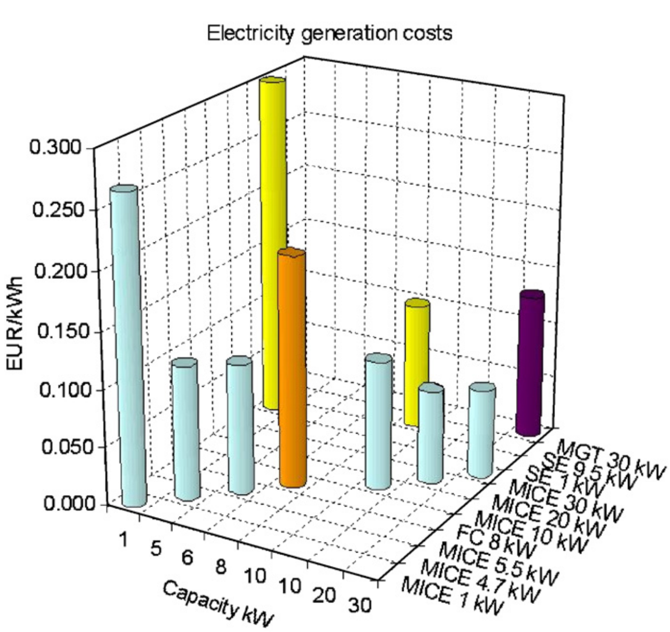

Fig. 2. Electricity generation costs for micro-cogeneration installations (<50 kW$_e$) calculated, $c_F = 3$ c€/kWh, $c_H = 3.6$ c€/kWh, $LF = 4000$ h/a.

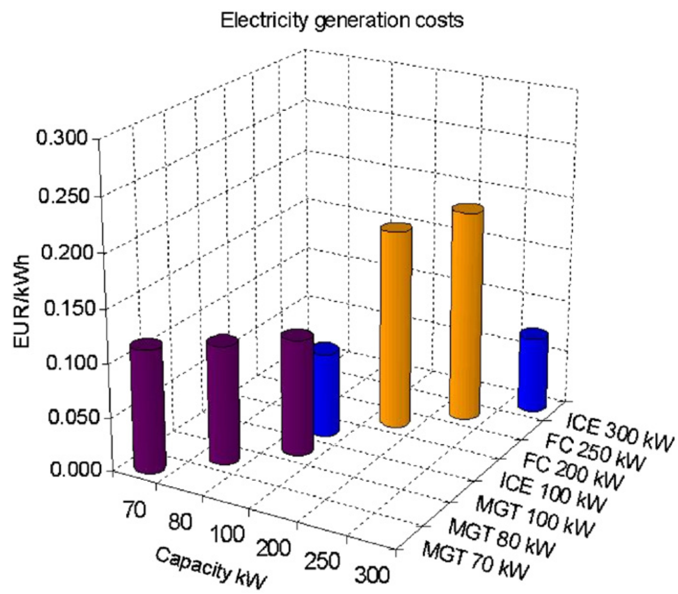

Fig. 3. Electricity generation costs for small cogeneration installations in capacity range between 50 kW$_e$ and 1 MW$_e$, $c_F = 3$ c€/kWh, $c_H = 3.6$ c€/kWh, $LF = 4000$ h/a.

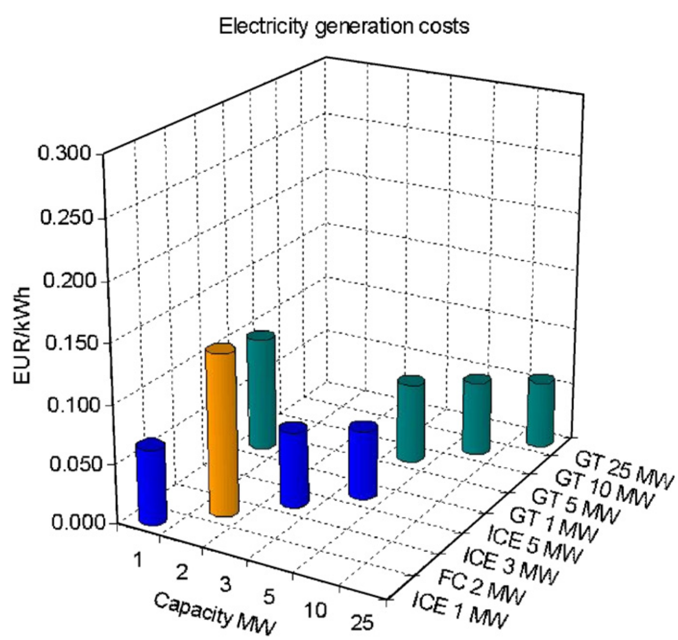

Fig. 4. Electricity generation costs for cogeneration installations in capacity range between 1 and 35 MW$_e$, $c_F = 2.5$ c€/kWh, $c_H = 3.0$ c€/kWh, $LF = 4000$ h/a.

Since the annual load factor and the fuel costs have an important influence on electricity generation costs of various cogeneration technologies, a sensitivity analysis has been performed. The results have been presented in Figs. 6 and 7.

In order to estimate the attractiveness of different cogeneration technologies in a typical national framework, calculated generation costs should be compared with electricity purchase prices and cogeneration feed-in tariffs. Although the comparison could be performed on separate figures, the more informative picture could be obtained by presenting as much data as possible on one figure.

An integral view has been proposed and presented in Fig. 8 where points denote values of calculated electricity generation costs in the whole considered range from 1 kW_e to 100 MW_e. Cogeneration technologies have been differentiated by colored curves. Each curve connects points calculated for the same gas price. Different gas prices have been denoted by different markers. A logarithmic abscissa enables comparison of cogeneration plants of different scale.

Dashed horizontal lines present average electricity purchase prices (including energy and all fees) for different customer categories in the year 2006 (households and businesses connected to low voltage, and customers connected to medium or high voltage). Horizontal solid lines present feed-in tariffs for electricity delivered from cogeneration plants with a status of privileged producer valid for different capacity ranges (1–50 kW, 50 kW_e–1 MW_e, 1 MW–35 MW and > 35 MW) and calculated as an average of peak and off-peak tariffs defined in Table 1. It should be stressed that electricity purchase prices are related to the connection level (high, medium or low voltage network) and to the type of customer (households or business) and they could be extended over one or more capacity intervals.

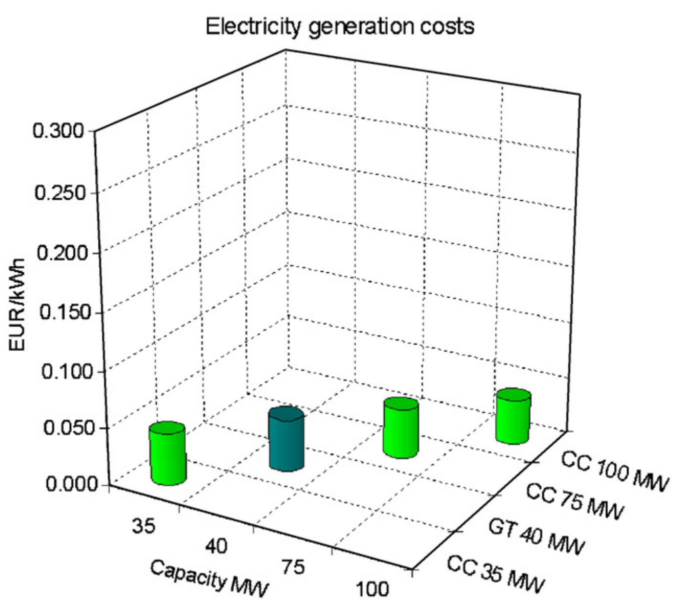

Fig. 5. Electricity generation costs for cogeneration installations bigger than 35 MW_e, $c_F = 2$ c€/kWh, $c_H = 2.4$ c€/kWh, $LF = 4000$ h/a.

Fig. 8 provides a simple way for an assessment of the attractiveness of the cogeneration system. The system will be profitable if the calculated price is positioned below the horizontal line. When the calculated point is positioned below the dashed horizontal line, the profitability of the system is assured through on-site consumption of the generated electricity while in cases when the calculated point is positioned below the solid horizontal line, the cogeneration system fully exporting generated electricity will be profitable too. It should be pointed out that the increase of load factor and the increase of heat prices positively affect profitability and translate technology curves towards lower electricity generation prices. Cogeneration systems below the solid horizontal line, thus being viable with exporting entire electricity generated, have to be thoroughly monitored.

The analysis of the presented data shows that most of small and medium-sized cogeneration systems based on internal combustion engines would be profitable. The profitability of the systems based on gas turbines depends on plant size and gas prices. Bigger systems capable of purchasing gas at lower prices would even be stimulated to export electricity. The graph suggests that operation of combined-cycle plants would be profitable at industrial sites, where electricity consumption exists and full load operation time could be longer than 4000 h/a. Investments into cogeneration plants based on fuel cells, micro gas turbines and Stirling engines would not be attractive under presented conditions as well as investment in most micro systems based on internal combustion engines, due to low subsidized residential electricity prices.

The graph, based on 2006 data, illustrates conditions in which the secondary legislation package was prepared and reflects intentions of the regulatory authorities towards activation of unexploited cogeneration potential by small and medium-sized units. In new circumstances, characterized by changing energy prices and rising environmental concerns, the exploitation of cogeneration benefits should be extended to the micro level. Besides reduction of primary fuel consumption and atmospheric emissions development of micro-cogeneration enables diversification of the heat and electricity production sources. The proposed graph gives a clear picture to which extent

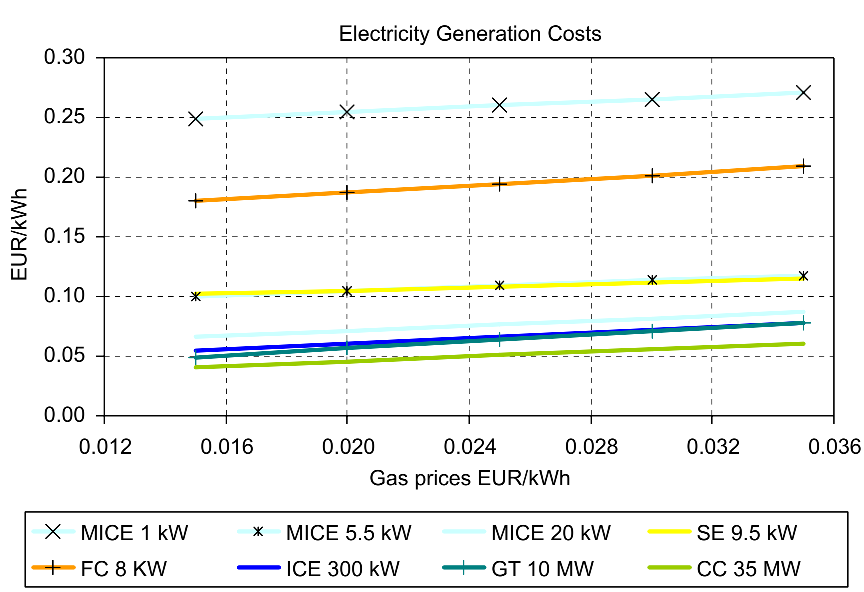

Fig. 6. Influence of the fuel price on the electricity generation costs, $c_H = 1.2c_F$, $LF = 4000$ h/a.

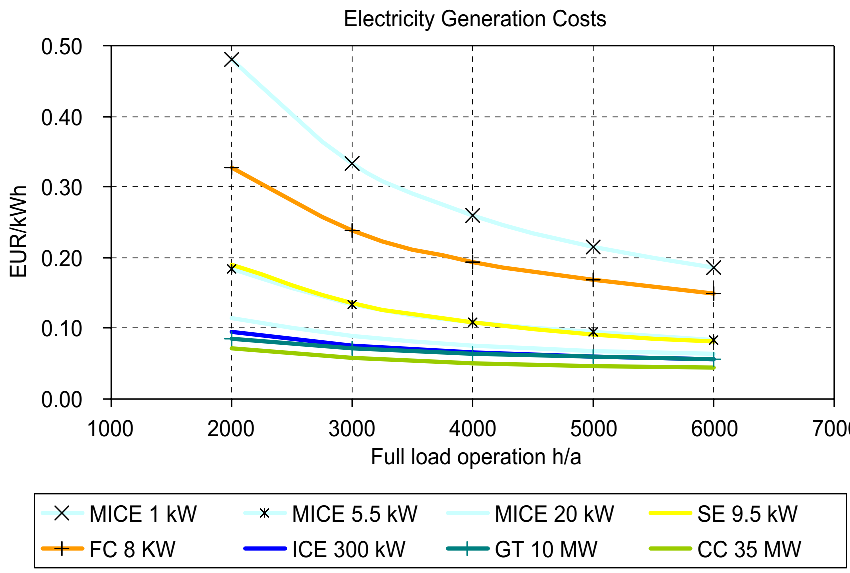

Fig. 7. Influence of the load factor on electricity generation costs $c_F = 2.5$ c€/kWh, $c_H = 3$ c€/kWh.

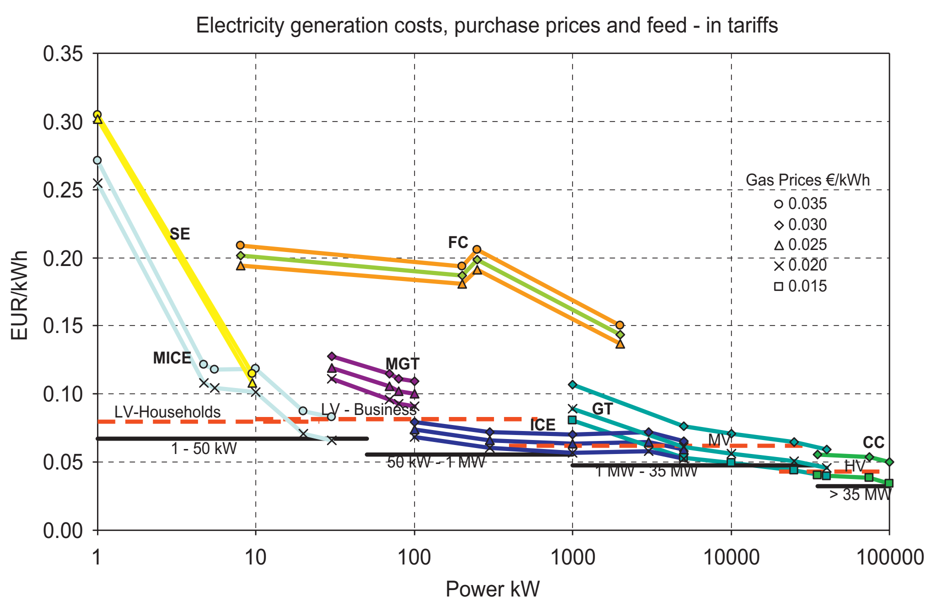

Fig. 8. Average electricity purchase prices (horizontal dashed), cogeneration feed-in tariffs (horizontal full) and electricity generation costs (points, calculated for assumed load factor of 4000 h/a and for different gas prices).

micro-cogeneration technologies should be supported either by gas price reduction or by increase of feed-in tariff.

5. Expected cogeneration sector development

5.1. District heating sector

A significant share of the Croatian cogeneration sector belongs to the district heating systems in the cities of Zagreb and Osijek with a total installed capacity of almost 500 MW_e and more than 1600 MW_t. Both systems are currently being renovated. The implementation of energy efficiency measures comprising network modernisation and the introduction of unit-based metering will strengthen the market position of these two systems which is currently being affected by expanding gas distribution services.

Besides cogeneration systems in big cities, there are several “heating only” district heating systems in other towns in continental Croatia. Most of them are obsolete or inefficient. Since such systems are burdening the owners with excessive running costs, the installation of smaller capacity cogeneration units presents a suitable and justifiable technological alternative. Prior to the adoption of secondary regulation, several projects for small-scale plants were started. The sustainability of these projects depends on the support of municipalities and this could be crucial particularly in heat price matters.

5.2. Industrial sector

Croatian industry has a significant cogeneration potential, as energy reduction costs are becoming an important factor for competitiveness increase. Total installed capacity in industrial cogeneration plants amounts to 208 MW_e. The adoption of secondary regulation motivated industrial producers to activate unused existing potentials. Existing legislative framework removes many barriers towards increased investment in industrial cogenerations. It ensures long-term contracts and protects privileged producers from the negative impact of energy market fluctuations through the feed-in price correction factor and the gas price protective clause. Recent electricity price increases (caused by increased import dependency and by the situation in regional electricity markets) enhance the appeal of cogeneration. There are plans for refurbishment, replacement or even expansion of several industrial power generating facilities in refineries, petrochemical industry and paper industry. It is expected that total installed capacity in industrial cogeneration plants will be higher than 380 MW_e in 2020 [42].

5.3. Residential and tertiary sector

Although the development of the gas distribution networks could be seen as a good prerequisite for increased penetration of micro units, current low retail energy prices and high specific investment costs do not favour investments in micro-cogeneration plants in the residential sector.

In the tertiary sector there is a vast but unexploited cogeneration potential. A number of stores and office buildings have been built in the last decade and conventionally connected to gas and electricity networks. Until now, cogeneration options in this sector have been considered as peripheral and as non-core business. Even though that has been slightly exacerbated by the low retail energy prices, the main barrier to cogeneration in residential and service sectors is inelasticity to energy prices, meaning that residential and service sector customers will give advantage to systems that are simpler than cogeneration systems. Therefore significantly increasing the feed-in tariff might not be enough to change investment decision in this sector. Even more, with a feed-in tariff that would be high enough to make micro-cogeneration economically viable it would be very difficult to devise mechanisms that would guarantee the origin of electricity in legislative context of transitional economy. The most efficient way around that barrier is the obligation method and not a feed-in tariff, transferring the decision and the investment cost of cogeneration to investors in buildings and thus avoiding residential and service sector customers to have to balance simplicity of the non-cogeneration systems and cost–benefit of the cogeneration.

6. Conclusions

Adoption of the new energy legislation and the establishment of a framework for systematic development and increased use of renewable sources and cogeneration mark the beginning of a new phase in the transition of the Croatian energy market. It is expected that in the short term the new regulatory framework will preserve the share of high-efficiency cogeneration in electricity generation. The adopted framework removes main barriers for efficient electricity production in cogeneration systems while not creating incentives to abuse. The chosen feed-in tariffs should improve the attractiveness of small to large industrial cogeneration systems. It has been shown that micro-cogeneration systems are difficult to support through presented model, and an obligation to install should be applied instead.

Presented methodological approach provides a quantitative illustration of the influence of diverse energy market conditions on cogeneration attractiveness. It was used by the authorities for evaluation to which extent implementation of various financial measures (feed-in tariffs, premiums for independent electricity sales, premiums for electricity use on site, tax exemption for gas prices, investment subsidies) influence the market attractiveness of different cogeneration technologies.

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