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Abstract

The Russian heat sector faces crucial problems including underinvestment, below cost pricing, generation capacity and infrastructure depletion. While the Russian electricity sector has gradually progressed through liberalization, the heat sector is still waiting for similar reforms to occur. The modernisation of the sector requires analysis of energy generation costs to suggest feasible technological solutions and secure an increase of investment in the industry. This study presents a modification of a levelised cost of energy (LCOE) model with cost separation coefficients based on Ginter triangles. The modified LCOE model is applied to a regional case study (Moscow, Russia) providing a comparison of generation technology according to cost estimates for electricity and heat under regionally specific economic and technological conditions. We consider five combined heat and power (CHP) generation technology types for two natural gas price scenarios. The modelling outcomes demonstrate cost competitiveness of gas based CHP technology and provide valuable information to assist decision making for the management of the energy sector in Russia.

Keywords: cogeneration, levelised cost, heat generation, Ginter triangle, Russia, Moscow

JEL Classification Codes: Q47; Q41; C52

1. Introduction

The modernization of the energy sector is one of the key factors for Russian sustainable economic growth and national wellbeing (IEA 2014). Considerable achievements have been made in the attrition of investment to the oil and gas industry and introduction of market mechanisms in the electricity sector (IEA 2014, Chernenko 2015). However, heat generation systems are a crucial part of the energy system in Russia and it remains unreformed and deteriorating (WB and IFC 2008). The reform of the national heating sector with the introduction of a competitive market for heat is still in the proposal stage (GRF 2014). Lack of investment, insufficient maintenance, pricing below cost and lack of government strategy in the heating sector over previous decades has led a decrease in the reliability of the Russian heat supply system (2010). Approximately 60% of the national heat and steam network needs replacement or major repair, including 25-30% crucially; more than half of the pipelines have exceeded their life expectancy. Furthermore, the World Bank has stressed that the Russian heat supply system is crucially in need of reshaping of its tariff methodology, improvement of statistical data collection and sectoral coordination, provision of heat consumption metrology, and transformation of mostly state owned producers to private entities (WB and IFC 2008). The existing tariffs are referred to as low, not covering the costs and discouraging improvements in energy efficiency (Trubaev, Gorodecskayu et al. 2014).

At the same time, an important feature of the currently operating energy system is the application of combined heat and power (CHP) or cogeneration technology in Russia which offers substantial potential for energy efficiency improvement in the country (IEA and OECD 2008, IEA 2010, Bashmakov 2011).

Russia is one of the leading countries in the use of CHP generation technologies where CHP's share of Russian power production is above 30%, which is provided by the World's second largest CHP installed capacity (IEA and OECD 2008).

Generally, CHP is characterised as reliable, cost-effective technology which can make an important contribution towards GHG reduction (IEA and OECD 2008). It is widely accepted that modern CHP plants can reach thermal efficiency of up to 90% when thermal load is sufficient (Schröder, Kunz et al. 2013) since reject heat is used in further generation processes (US DOE 2000, Rosen, Le et al. 2005) and that reduction of emissions can be as high as 50% (Worley Parsons 2013). CHP is currently experiencing increasing world wide deployment. The EU generates around 11% of electricity by means of CHP with Denmark, Finland and the Netherlands leading countries (IEA 2011). The EU acknowledges that cogeneration is an untapped reserve for saving primary energy in Europe (EU 2012). Although Eastern European countries, including Russia, are characterised by higher levels of CHP penetration, the efficiency of CHP generation in this region is a matter for discussion. Existing cogeneration plants are often referred to as redundant and low-efficiency plants (Schröder, Kunz et al. 2013). At the same time, according to IEA, a lack of reliable information exists on the efficiency of existing CHP plants in Russia (IEA 2010). Furthermore, Russia still has potential for CHP expansion in light of energy demand growth (IEA and OECD 2008).

Given the importance of heat sector modernisation, energy efficiency improvement potential provided by cogeneration and the lack of economic analysis of existing and new CHP energy generation in Russia, this study specifically considers CHP as a generation technology for heat and electricity. The paper determines the generation costs for heat and electricity in the CHP cycle by modifying a levelised cost of energy (LCOE) model with cost separation coefficients. Although the LCOE is a well-established, robust and widely applied method for electricity generation cost modelling, it is rarely used for the analysis of heat generation within CHP. This study seeks to contribute to the discussion of the cost of heat generation in a combined cycle and present a novel solution to this problem.

This paper also provides an application of the suggested approach to a regional case study to consider the cost competitiveness of five different technology types. Specifically, we consider the Moscow region as a case study. Together, Moscow and the Moscow Region account for 11.7% of national energy use of which 35% is consumed as electricity and 65% as heat (FSSS 2011). Heat supply in Moscow is met by CHP generation (77%), and district and local heat plants (22%).

The remainder of this paper is presented as follows: the next section introduces our research methodology with a modification of the LCOE. Section 3 specifies assumptions for the case study. The results of the study and their discussion are provided in Section 4. Section 5 concludes the study.

2. Research methods

LCOE is one of various tools for economic analysis applied widely in the energy sector research. LCOE had a demonstrated reliability and is applied as a decision support tool for international, national (Electric Power Research Institute 2010, EIA 2011, BREE 2012, Natural Resources Canada 2013, Schröder, Kunz et al. 2013, US DOE and NREL 2013) regional and local studies (CEC 2007, CEC 2009, Klein 2009, Branker, Pathak et al. 2011, CEC 2011). The transparency and robustness of the LCOE approach has determined its popularity for the analysis of cost performance of energy generation options.

However, LCOE is rarely used for Russian energy sector analysis. Furthermore, although CHP shows great potential to meet future energy needs at low cost, it is not always considered in LCOE applications (for instance, LCOE models developed and published by the Australian Bureau of Resources and Energy Economics (BREE 2012), the California Energy Commission (CEC) (Cost of Generation model (CEC 2009)), and the US DOE (NREL) omit cogeneration).

Limited LCOE applications for CHP analysis can be explained by a number of factors. Firstly, the cogeneration production cycle is complex and faces lack of data availability. Secondly, LCOE models are mostly developed to analyse the electricity generation sector focusing on determination of electricity generation costs only. Thus, heat is frequently treated as a by-product or a source of revenue decreasing per unit costs of electricity generation (IEA and NEA 2010, DECC 2011, DECC 2013). However, modelling of cogeneration technology costs in comparison with other existing energy generation technology is important for the exploration of energy generation options for Russia.

2.1 Cost of energy generation: standard approaches

The methodological basis of this study is the LCOE function adopted from Wagner and Foster (2011):

$$LCOE_j = \frac{\sum_{t=1}^{n} \frac{TOC(t)_j + Capex(t)_j}{(1+WACC)^t}}{\sum_{t=1}^{n} \frac{\mathrm{SOR(t)}_j}{(1+WACC)^t}} \qquad 1.$$

It defines the cost of energy generation ($LCOE_j$) for a technology (*j*) over the lifetime (*n*), taking into account discounted capital costs ($Capex(t)_j$) and operating costs ($TOC(t)_j$) per unit of energy output ($SOR(t)_j$). Weighted average cost of capital is considered as a discount factor (*WACC).*

Due to the dual nature of the energy outputs from cogenerating plants, specific economic and accounting approaches need to be adopted to separate the costs between the two products – heat and power. Failure to separate costs can lead to the conclusion that CHP technologies are inefficient due to high costs. Recent discussion in the literature regarding CHP in Russia provides a good example of the importance of the cost separation (Nagornaya 2007, Bashmakov, Borisov et al. 2008, Nigmatulin 2011), suggesting that more detailed consideration of different practices of cost accounting for CHP is necessary.

2.1.1 Physical (balance) method and heat credit

The physical or balance method of cost separation is used by the Ministry of Energy of the Russian Federation (Nagornaya 2007) and therefore by the Russian generating companies (Mosenergo 2011). According to this method, costs for heat production are calculated as if the heat was generated separately (for example, by a boiler) rather than in the cogeneration cycle (Zharkov 2007).

The supporters of this method advocate that it provides transparent and accountable results, doesn't suffer from unnecessary assumptions, and allows for seasonal fluctuations in output levels (Rogalev 2005, KES 2014). The major disadvantage of this method is that any cost decrease due to CHP generation is accounted for in electricity production only. The cost of heat production increases but electricity production costs decline at CHP plants in comparison to solely electricity plants (Pokrovsky, Taraday et al. 2000, Nagornaya 2007). An example by Nagornaya (2007) shows that the average heat rate generated at thermal power plants (CHP plants), when calculated according to the physical method, becomes equal 0.18-0.25 kgce[1]/kWh in comparison to 0.32 kgce /kWh at large scale power plants, which is interpreted as an underestimation of the electricity generation costs for CHP producers.

Moreover, the application of the physical method requires a determination of the cost of heat generation by boilers. Review of energy generating company reports shows that no consistent data is publically available to source the generating costs for heat generation only. This limits the applicability of the physical method of cost separation for research and decision making.

Another approach of the same basis is the application of "heat credits". The heat credit, also referred to as revenue from heat generation, is defined as the value of heat sent out by the CHP plant calculated per unit of electricity generated by the plant over its lifetime. This approach has become conventional in LCOE applications when CHP technology is considered (IEA and NEA 2010, Mott MacDonald 2010, Schröder, Kunz et al. 2013).

Mott MacDonald (2010) applies a similar approach when defining thermal efficiency for electricity generation by CHP plants, targeting separation of fuel costs. This method is also referred to as "avoided gas boiler methodology" (DECC 2011, PB 2012, DECC 2013, PB 2013). These studies suggest the concept of incremental fuel costs to determine CHP thermal efficiency. In this case electricity is assumed to be the main and most valuable product where incremental fuel use is defined as total fuel use by the plant less the fuel which would be required if heat was produced separately.

Heat credits and the physical method of cost separation are transparent and widely used approaches. However, by targeting electricity generation costs, they don't allow for the estimation of the real cost of heat production by CHP plants. Furthermore, an important limitation of the heat credit approach is, that the heat credit rate is utilised as a single value for any generating plant operating in the CHP mode without

[1] Kgce - kilograms of coal equivalent.

considering technology specific features of the generation. The objective of this study is to develop a technique which would allow for the determination of the costs for each of the energy products. We now explore other approaches in the literature and compare and contrast their findings with the methodology we propose.

2.1.2 Ginter triangle as an alternative approach

One approach to cost separation of electricity and heat was suggested by the Russian engineer - L.L. Ginter (1876-1932) (Semenov 2003, Gaidai and Lisenko 2010). This approach, named the "Ginter triangle", is based on similar principles to the construction of a budget line in consumer theory. A triangle is developed in the space between two axes - costs for electricity and heat (see figure 1). The triangle enables estimation of the unit cost of the second product assuming the unit cost of the first one. Points A and B show unit costs if only one product was generated (Zharkov 2007).

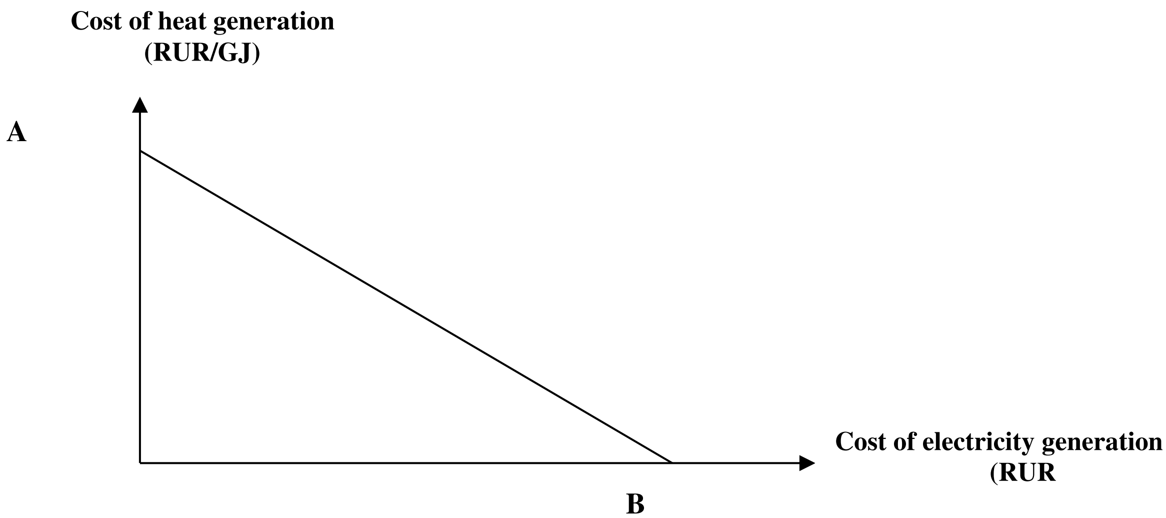

Figure 1 Ginter triangle for cost separation

Source: Nagornaya (2007)

Compared to the heat credit and physical method approaches, the Ginter triangle enables the calculation of the cost of each energy product generated, therefore it is adopted for this study and discussed in section 2.2.

2.1.3 Other approaches to costs separation for the cogeneration modelling

Another approach to cost separation is utilised by the UK statisticians in their annual "The Digest of UK energy statistics" (DECC 2013) which uses an efficiency based approach for fuel cost separation for statistical purposes. It is observed that the efficiency of electricity generation varies from 25% to 50% whereas the boilers' efficiency reaches 50-90%. The DECC concludes that a unit of electricity is nearly twice as difficult to generate as a unit of heat (DECC 2013). Fuel costs are then allocated accordingly among energy products acknowledging that energy generation in CHP provides costs savings for both heat and power sectors. However, they note that the allocation of fuel costs to heat and power generation is not determinate, but notional (DECC 2013). The same approach is recommended by some national and international agreements and government manuals (DEFRA and DECC 2012).

Generally, it is acknowledged that cost separation using coefficients or alternative methods for splitting the generation costs is likely to attract significant criticism. The IEA study for the projection of electricity generation costs via the LCOE method since 1983 claimed that the cost share separation is "highly impractical" since heat and power are genuine joint products (IEA and NEA 2010, p.40). This claim is referred to in a number of studies to justify not attempting to separate these costs (Schröder, Kunz et al. 2013). Other approaches to cost separation are also widely discussed in the literature including a method based on norms, exergy calculation and a proportional method (Pokrovsky, Taraday et al. 2000, Rogalev 2005). Some researchers suggest not separating costs at all as there is no agreement on the basis for the separation, and consider the single energy product of cogeneration (Sterman, Tishin et al. 1996, Gaidai and Lisenko 2010). Others emphasize that since there is no reliable and theoretically established approach to cost separation based on the properties of energy output, the current separation practise is neither better nor worse than any other, but provides at least some estimates of production costs for each generated product (Haraim 2003).

Having outlined several basic approaches to the costs allocation among energy products in CHP generation, this study proposes the Ginter method as a useful approach for cost separation and as offering a suitable modification to the standard LCOE model. At the same time we apply the conventional heat credit approach to comment on the differences in the estimated modelling outcomes.

2.2 Modified LCOE: application of separation coefficients

The application of the Ginter method of costs separation requires the use of separation coefficients to allow for separation of costs associated with combined generation. The LCOE function is transformed to calculate the LCOE for a unit of electricity ($LCOE_j^E$, equation 2) and a unit of heat ($LCOE_j^H$ equation 3).

$$LCOE_j^E = \frac{\sum_{t=1}^{n} \frac{TOC(t)_j^E + Capex(t)_j^E}{(1+WACC)^t}}{\sum_{t=1}^{n} \frac{\mathrm{SOR(t)}_j^E}{(1+WACC)^t}} \qquad 2.$$

$$LCOE_j^H = \frac{\sum_{t=1}^{n} \frac{TOC(t)_j^H + Capex(t)_j^H}{(1+WACC)^t}}{\sum_{t=1}^{n} \frac{\mathrm{SOR(t)}_j^H}{(1+WACC)^t}} \qquad 3.$$

Table 1 provides detailed parameters for the constructed model. Two sets of separation coefficients are used:

c_j^E, c_j^H - separation coefficients for capital costs;

k_j^E, k_j^H - separation coefficient for other generating costs.

For the cogeneration plants the model required initial entry of single values for most cost parameters with subsequent separation into heat and electricity generation cost components as demonstrated in table 1. Other variables describing generating plants need to be entered separately for heat and power generating blocks of CHP plants (e.g. plant size, capacity factor, and auxiliary energy use). The assumptions for these parameters and the list of generation technologies are discussed in detail section 3.

This model assumes the application of growth parameters separately for revenue flow ($I(\mathrm{t})_{\mathrm{R}}$) and cost flow ($I(\mathrm{t})_{\mathrm{C}}$). The original LCOE model (Wagner and Foster 2011) applies CPI with cost and revenue pass through rates to reflect the growth parameter and ensure that the developed model acknowledges the fact that revenue and costs for generating companies are anticipated to increase at different rates. This research follows this approach and introduces $I(\mathrm{t})_{\mathrm{R}}$ and $I(\mathrm{t})_{\mathrm{C}}$ parameters.

The determination of the separation coefficients for the cost components is complex due to the physical properties of simultaneous production. We apply risk analysis using a Monte Carlo simulation to determine cost ranges for energy products as further discussed in section 3.3. The next section details the heat credit approach to be used in the LCOE model for comparative purposes.

Table 1 Modified LCOE model components

Parameter	Electricity generation	Heat generation
Costs		
Fixed operating and maintenance	$FOM(t)_j^E = FOM(t)_j \cdot k_j^E$ $FOM(t+1)_j^E = FOM(t)_j^E \cdot I(t)_C$	$FOM(t)_j^H = FOM(t)_j \cdot k_j^H$ $FOM(t+1)_j^H = FOM(t)_j^H \cdot I(t)_C$
Variable operating and maintenance	$VOC(t)_j^E = VOC(t)_j \cdot k_j^E$ $VOM(t+1)_j^E = VOC(t)_j^E \cdot SO(t)_j^E \cdot I(t)_C$	$VOC(t)_j^H = VOC(t)_j \cdot k_j^H$ $VOM(t+1)_j^H = VOC(t)_j^H \cdot SO(t)_j^H \cdot I(t)_C$
Fuel	$Fuel(t)_j^E = \left(\frac{(HR_j * k_j^E) * CF_j^E * FC(t)_j}{1000}\right) \cdot SO(t)_j^E \cdot I(t)_C$	$Fuel(t)_j^H = \left(\frac{(HR_j * k_j^H) * CF_j^H * FC(t)_j}{1000}\right) \cdot SO(t)_j^H \cdot I(t)_C$
Total	$TOC(t)_j^E = Fuel(t)_j^E + FOM(t)_j^E + VOM(t)_j^E + CM(t)_j^E$	$TOC(t)_j^E = Fuel(t)_j^E + FOM(t)_j^E + VOM(t)_j^E + CM(t)_j^E$
Capital	$Capex(t)_j^E = c_j^E * Capex(t)_j$	$Capex(t)_j^H = c_j^H * Capex(t)_j$
Technology depletion	$CM(t)_j^E = \frac{CF_j^E \cdot Capex(t)_j^E \cdot I(t)_C}{life_j}$	$CM(t)_j^H = \frac{CF_j^H \cdot Capex(t)_j^H \cdot I(t)_C}{life_j}$
Output and revenue		
Energy produced (per annum) Auxilary energy use	$SO(t)_j^E = \frac{size_j^E \cdot CF_j^E \cdot 8670 \cdot (1 - Aux_j^E)}{1000}$ Aux_j^E	$SO(t)_j^H = \frac{size_j^H \cdot CF_j^H \cdot 8670 \cdot (1 - Aux_j^H)}{1000}$ Aux_j^H
Revenue flow from energy production	$SOR(t)_j^E = SO(t)_j^E \cdot I(t)_R$	$SOR(t)_j^H = SO(t)_j^H \cdot I(t)_R$
Capacity factor	CF_j^E	CF_j^H

2.3 Heat credit approach: incorporation into the LCOE model

To apply the heat credit approach in the LCOE model, the heat credit in functional form is defined as follows:

$$HC(t)_j = \frac{HCR * \mathrm{SO(t)}_j^H}{\mathrm{SO(t)}_j^E}\text{, where} \qquad 4.$$

$HC(t)_j$ - heat credit for technology j in year t (per MWh of electricity generated);

HCR - heat credit rate;

$\mathrm{SO(t)}_j^H$ - sent out heat (MWh) by the plant of technology j in year t;

$\mathrm{SO(t)}_j^E$ - sent out electricity (MWh) by the plant of technology j in year t

Heat credits are therefore expected to reflect the value of heat generated in the CHP cycle. The electricity generating cost is therefore defined as the difference between total energy production costs and the value of heat produced:

$$TOC(t)_j^E = TOC(t)_j - HC(t)_j * \mathrm{SO(t)}_j^H\text{, where} \qquad 5.$$

$TOC(t)_j^E$ - total cost of electricity generation in period t by technology j;

$TOC(t)_j$ - total generation costs of generation by the technology j in period t.

Following the standard LCOE approach described in section 2.1, the heat credit can be "levelised":

$$LHC_j = \frac{\sum_{t=1}^{n} \frac{HCR * SO(t)_j^H}{(1+WACC)^t}}{\sum_{t=1}^{n} \frac{\mathrm{SOR(t)}_j^E}{(1+WACC)^t}}\text{, where} \qquad 6.$$

$\mathrm{SOR(t)}_j^H, \mathrm{SOR(t)}_j^E$ - sent out heat and electricity respectively.

The function (equation 6) provides an estimate of a levelised heat credit (LHC_j) as the value of heat credit per unit of electricity produced over the plant life expressed in RUR per MWh.

The described heat credit approach provides a transparent way of cost separation for cogeneration. However, it raises the question of how to calculate the value of the heat credit rate (*HCR*). Values assumed for heat credits vary in the economic literature. For example, DIW Berlin provides a review of studies showing that values of 33-37 EUR per MWh of thermal energy (heat) generated are often used (Schröder, Kunz et al. 2013). They also specify values for coal based technologies (42-51

EUR/MWh of heat); natural gas based technologies (9-32 EUR/MWh of heat) and biogas technologies (13.5 EUR/MWh of heat) (Schröder, Kunz et al. 2013).

The IEA suggests an estimate of 45 USD/MWh of heat credit for OECD countries (2010) and 25.8 USD per MWh of heat for generating plants in Russia. This value is estimated as a forecasted heat tariff for Russia for the period after 2015. It results in approximately 859.1 RUR/MWh of heat. This value is applied in this study for the Russian regional case study. The next section outlines technological and financial assumptions for the modified LCOE model for the case study.

3. Technological and financial parameters of the model

3.1 Technological assumptions

The CHP technology types considered in this case study are selected given the data available at the time of research. Specifically CHP generation is modelled for pulverized black coal combustion (PCC); large and small natural gas combined cycle gas turbine (CCGT) and large and small conventional gas turbine plants.

Technological assumptions are summarised in the table 2 and discussed below.

Table 2 Technological and costs assumptions for the LCOE model

Technology	Installed capacity, MW		Capital costs	Thermal efficiency	Capacity factor,%	
	Electricity	Heat	RUR/kW	%	Electricity	Heat
Black Coal PCC	103	229	93,020	56.7	63	44
Gas CCGT Large	415	437	48,060	77	63	44
Gas CCGT Small	44	46	64,957	77	63	44
Gas Turbine Large	101	184	42,827	71	63	44
Gas Turbine Small	24	44	53,825	71	63	44

Technology	Construction profile	Lifetime of plants, years	O&M costs	Capex main.rate	Auxiliary use, %	
				%	Electricity	Heat
Black Coal PCC	Years 1 to 4 - 25% each	40	431.6	0.16	92	100
Gas CCGT Large	Year 1 – 50%; Year 2 – 50%	30	293.3	0.21	97	100
Gas CCGT Small		30	396.6	0.21	97	100
Gas Turbine Large		30	261.6	0.21	97	100
Gas Turbine Small		30	328.6	0.21	97	100

Source: (Klein 2009, CEC 2010, IEA and NEA 2010, Wagner and Foster 2011, BREE 2012)

The majority of assumptions have been adopted from the IEA/NEA study in their estimates for the Russian energy system (IEA and NEA 2010), which are based on submissions from the regional generating companies. The values are adjusted for this study via conversion to 2010 RUR using the IEA exchange rate of 24.85 RUR/USD with an inflation rate of 1.34 sourced from national statistics (FSSS 2011). The construction profile assumptions are sourced from international studies (Klein 2009, CEC 2010, IEA and NEA 2010, BREE 2012), capex maintenance rates are sourced from the study by Wagner and Foster (2011).

Separate installed capacity values for each energy product are assumed as required by the model (table 1). The proportion of installed capacity for electricity and heat generation within existing regional CHP plants varies substantially depending on the technology used, period of plant construction and plant technological features (Mosenergo 2000).

Current European legislation recommends ratios of heat and power generation for modern CHP plants referred to as “quality CHP” (EU 2004). The standard power-to-heat ratio for CHP generation is defined as a ratio of electricity from cogeneration to useful heat when operating in full cogeneration mode. The EU power to heat ratios are applied in this research as the indicative basis for determination of the installed heat capacity (table 2). It is acknowledged, however, that the EU directives apply the ratio to the energy output rather than capacity.

CHP technology is well established and has been in use for over 100 years (Rosen, Le et al. 2005), therefore no capital cost depletion due to technology learning was allowed for in the model.

Given that the data source (IEA and NEA 2010) doesn’t provide separate estimates for fixed (FOM) and variable (VOM) operating and maintenance costs, the former is included in the latter and presented in the model as a single parameter (O&M costs).

3.2 Financial assumptions

We have applied a weighted average cost of capital (WACC) to account for the opportunity cost of capital and to allow for discounting in the model. An estimate of 13.92% for the post tax nominal rate for WACC has been applied in this study as developed for the current regional and national financial parameters (Bratanova, Robinson et al. 2012c). This corresponds to the discount factor of 14% recommended by the electricity market operator to be used for capacity trading contracts (NP Market Council 2011).

Fuel cost is one of the major components of unit generation cost for CHP generators. Natural gas prices remain regulated in Russia and are reported to be substantially lower for domestic consumers as compared to export prices (Orlov 2015). As demonstrated by Paltsev (2014), in 2009-2013 domestic consumers paid approximately 30% of the price charged to European consumers for natural gas. However, international studies for Russia project that the domestic prices will reach parity with Russian export prices for the netback EU (IEA and NEA 2010). The latter can be treated as a shadow price of natural gas given Russia’s high involvement in the international trade of natural gas. Consequently, this study considers two gas price scenarios:

- Scenario 1: domestic price of natural gas of 85 RUR/GJ;
- Scenario 2: a price of 195 RUR/GJ reflecting the price for neighbouring countries.

For coal based generators a price of 81.2 RUR/GJ (in 2010 values) is assumed as sourced from the national statistics (FSSS 2011).

3.3 Simulation approach to the determination of separation coefficients

Application of Monte Carlo simulation allows us to derive possible combinations of separation coefficients for capex and O&M costs and to build probability distribution functions for LCOE estimates. *ExcelSim,* an add-in for *MS Excel,* is utilized for the separation coefficient determination in the risk analysis framework. This approach is based on the assumption that there are multiple bases for cost separation in the CHP cycle of energy generation (as discussed in section 2.1). However, it can also be assumed that the separation coefficients for capex and O&M costs vary within a 10% - 90% range of the total generation costs. This assumption is based on the expectation that a CHP plant always bears costs associated with the generation of both energy products. For instance, even when a plant operates in the electricity generation only mode, it is required to maintain and service heat generating facilities and equipment which results in associated O&M costs. A triangular distribution for the estimation of the separation coefficients is used to undertake the simulation and construct probability distributions for heat and electricity LCOE estimates.

Having outlined the assumptions of the study, the next section presents the results of the modeling for each of the two scenarios and for electricity and heat.

4. Results and discussion. Limitations

4.1 LCOE estimation for Scenario 1

4.1.1 Electricity generation

The Monte Carlo simulation[2] enables us to determine ranges for the unit electricity generation costs for each technology under consideration. The estimated values for approximately 50%, 90% and 95% percentile points for the obtained probability distributions of electricity generation costs are summarized in table 3.

Table 3 Electricity generation cost estimates for CHP (Scenario 1)

Probability level	LCOE, RUR/MWh				
	Black Coal PCC	CCGT Large	CCGT Small	Gas Turbine Large	Gas Turbine Small
50%	1492	893	1121	856	1004
90%	1980	1194	1476	1116	1304
95%	2103	1247	1564	1181	1383

Source: LCOE results

[2] The simulation is run with the following parameters: triangular distribution, with 0.1 and 0.9 as left and right thresholds, 0.5 as a mode; number of iterations, 5000.

Analysis reveals that the unit electricity generation cost for black coal PCC plants has a 95% probability of falling below 2103 RUR/MWh. At the same time, the LCOE for electricity generation by the CCGT plant of a large size is estimated to be 1247 RUR/MWh, which is approximately 25% lower than the value obtained for the small generator with the same technology (1564 RUR/MWh).

The large sized gas turbine generation provides the best estimate for the unit electricity generation costs, 1181 RUR/MWh (with a 95% probability).

4.1.2 Heat generation

Heat generation costs obtained from the modified LCOE model are summarized in table 4. Large gas turbine plants show the best performance of unit generation cost estimates for heat. Specifically, there is a 95% probability that the unit generation cost for a large gas turbine is 1376 RUR/MWh of heat, which is ~19% lower than for the small gas turbine (1641 RUR/MWh of heat). CCGT shows unit generation costs of 1874 RUR/MWh of heat and 1448 RUR/MWh of heat for small and large plants respectively.

The modelling demonstrates that there is a 95% probability that unit heat generation costs are under 2337 RUR/MWh for black coal based generators.

Table 4 Heat generation costs estimates for CHP (Scenario 1)

Probability level	LCOE, RUR/MWh				
	Black Coal PCC	CCGT Large	CCGT Small	Gas Turbine Large	Gas Turbine Small
50%	1685	1068	1333	993	1165
90%	2207	1368	1766	1275	1540
95%	2337	1448	1874	1376	1641

Source: LCOE results

4.2 Estimation for Scenario 2

4.2.1 Electricity generation

The cost estimates for electricity generation in Scenario 2 are presented in table 5. Given the higher price for natural gas, electricity generation costs for the gas-based technology show an expected increase in the second Scenario when compared to Scenario one. The opportunity cost of natural gas and the associated increase in price by approximately 129% resulted in the electricity generation cost increasing by 31% (CCGT small) to 44% (gas turbine large) for the natural gas based technology types for CHP (see figure 2). However, the unit generation costs of electricity for all gas based technology types remain lower than cost estimates for black coal PCC (table 5). This observation is interesting as it demonstrates that the gas fueled CHP is substantially outperforming coal fueled CHP, such that even a gas price increase doesn't affect their relative ranking on the unit generation cost scale.

Table 5 Electricity generation costs estimates for CHP (Scenario 2)

Probability level	LCOE, RUR/MWh			
	CCGT Large	CCGT Small	Gas Turbine Large	Gas Turbine Small
50%	1247	1475	1225	1377
90%	1634	1929	1603	1809
95%	1738	2043	1697	1917

Source: LCOE results

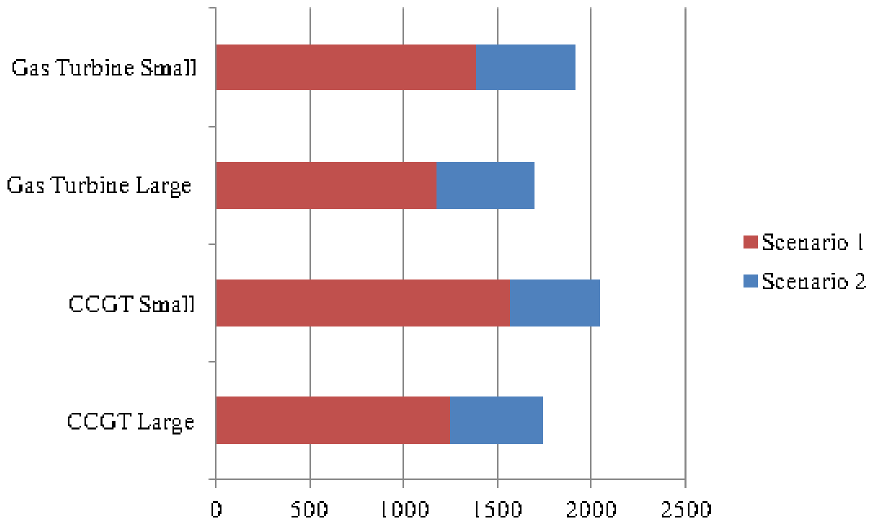

Figure 2 Electricity generation cost for CHP technology: scenarios comparison

Source: LCOE results

4.2.2 Heat generation

The LCOE estimates for heat in Scenario 2 are provided in table 6. Analysis shows that the best performance is demonstrated by large gas turbine technology (1886 RUR/MWh of heat at 95% probability), followed by large CCGT (1927 RUR/MWh of heat). The highest cost estimate for natural gas based plants is obtained for small CCGT. However, all natural gas based technologies show better cost parameters than the black coal PCC (2364 RUR/MWh of heat).

Table 6 Heat generation costs estimates for CHP (Scenario 2)

Probability level	LCOE, RUR/MWh			
	CCGT Large	CCGT Small	Gas Turbine Large	Gas Turbine Small
50%	1389	1657	1365	1522
90%	1814	2151	1756	2016

95%	1927	2282	1886	2139

Source: LCOE results

The LCOE for heat in the second Scenario exceeds the values in the first Scenario by 22% (CCGT small) to 37% (small gas turbine), as illustrated in figure 3. This difference between the scenarios is lower than the same parameter observed for electricity generation (31-44%, figure 2). Based on a 129% increase in the fuel price between the scenarios, this difference in heat generation LCOE is moderate. Therefore heat generation costs are shown to be less sensitive to the fuel price.

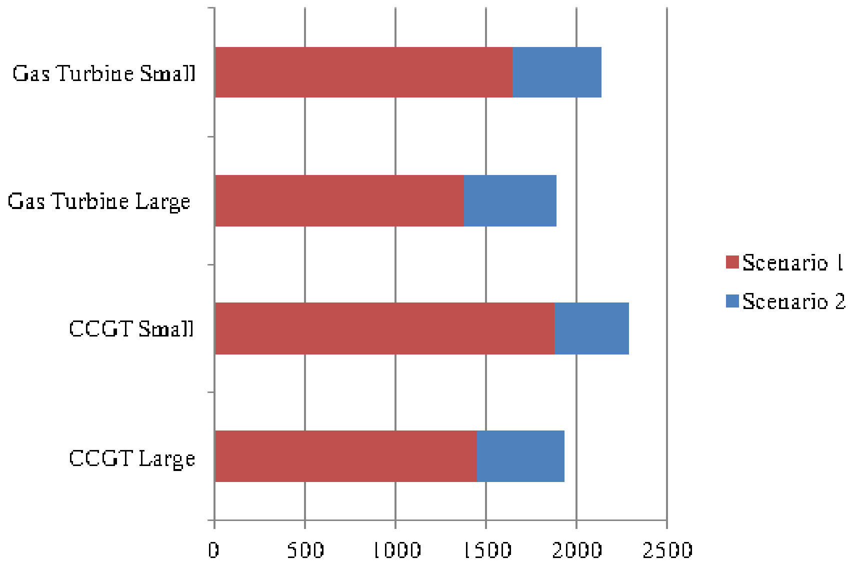

Figure 3 Heat generation costs for CHP: scenarios comparison

Source: LCOE modelling results

Having outlined and discussed the results of the application of the modified LCOE, it is necessary to compare these results to those from the widely used heat credit approach. This is undertaken in the next section.

4.3 Heat credit approach

The heat credit values, based on the assumed plants' technological parameters and the heat credit rate for the Moscow regional case study, are provided in table 7. The total LCOE is calculated when all generation costs are accounted for. The parameter "LCOE for electricity" is therefore determined as the difference between total LCOE and the heat credit for each technology.

The obtained heat credit values are observed to be lower than the LCOE estimates for heat, obtained earlier using the separation coefficients facilitated by a Monte Carlo simulation. This observation holds for all the considered technology types and for 50%, 90% and 95% probability levels. This raises a discussion about the feasibility and reliability of the obtained modified LCOE estimates when compared to the heat credit value used in international studies. This discussion can be facilitated with Ginter triangles.

Table 7 Heat credit estimates for CHP

Technology	Heat credit, RUR/MWh	Scenario 1		Scenario 2	
		LCOE total	LCOE of electricity	LCOE total	LCOE of electricity
Black Coal PCC	1451	2982	1531	2982	1531
Gas CCGT Large	653	1793	1140	2468	1815
Gas CCGT Small	653	2240	1587	2915	2262
Gas Turbine Large	1127	1699	572	2431	1304
Gas Turbine Small	1127	1990	863	2722	1594

Source: LCOE results

4.4 Ginter triangles: comparison of the outcomes

Ginter triangles are constructed for both electricity and heat (figures 4–8) with the estimates demonstrated in table 8, (the key points' description is summarized in table 9).

Table 8 LCOE parameters for construction of Ginter triangles

Technology type	Scenario 1		Scenario 2	
	Electricity axis	Heat axis	Electricity axis	Heat axis
Black Coal PCC	2982	3343	2982	3343
Gas CCGT Large	1793	2098	2468	2752
Gas CCGT Small	2240	2657	2915	3312
Gas Turbine Large	1699	1967	2431	2677
Gas Turbine Small	1990	2331	2722	3041

Source: LCOE results

Different slopes or substitution rates are observed for different technology types as determined by the specific characteristics of the CHP technology. To avoid double counting, as both electricity and heat unit generation cost estimates are mapped simultaneously, 50% probability levels were applied for the construction of points E and F.

Table 9 Key points for the constructed Ginter triangles

<table>
<tr><th>Point</th><th colspan="2">Interpretation</th></tr>
<tr><td>C</td><td rowspan="2">estimates with application of heat credit approach</td><td>Scenario 1</td></tr>
<tr><td>D</td><td>Scenario 2</td></tr>
<tr><td>E</td><td rowspan="2">estimates utilizing modified LCOE</td><td>Scenario 1</td></tr>
<tr><td>F</td><td>Scenario 2</td></tr>
</table>

Source: LCOE modelling results

Ginter triangles for CCGT of large and small sizes (figures 4, 5) demonstrate that heat credit based LCOE estimates (points C, D) lean toward electricity generation resulting in substantially higher electricity unit generation costs as compared to heat. The same results, but with a smaller magnitude, are demonstrated for gas turbine-based technology for Scenario 2 (figures 6, 7).

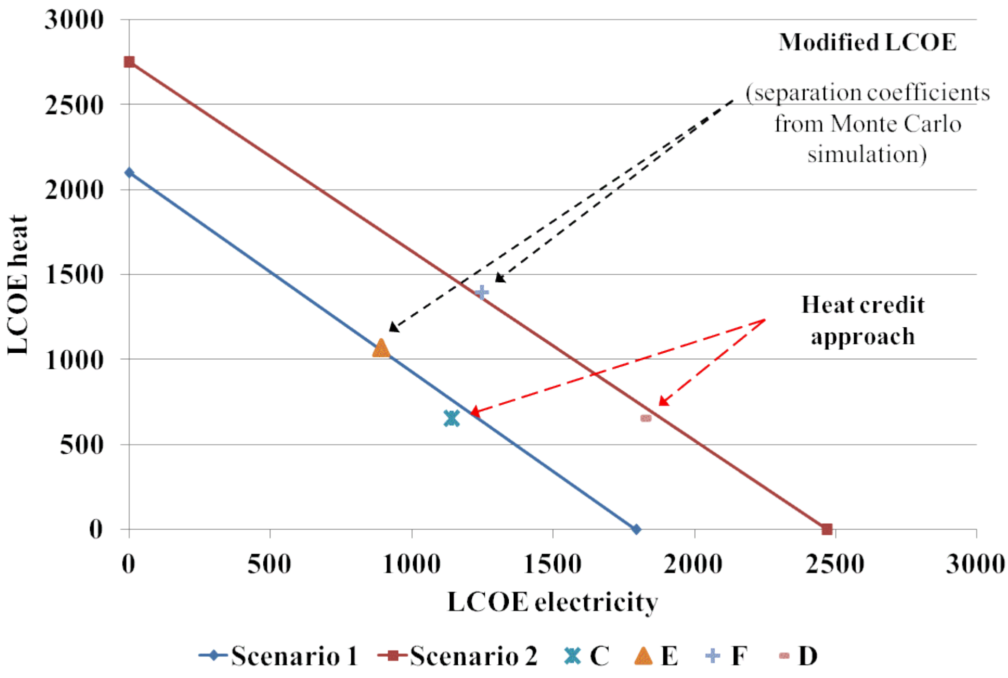

Figure 4 Ginter triangle for the Gas CCGT Large

Source: LCOE results

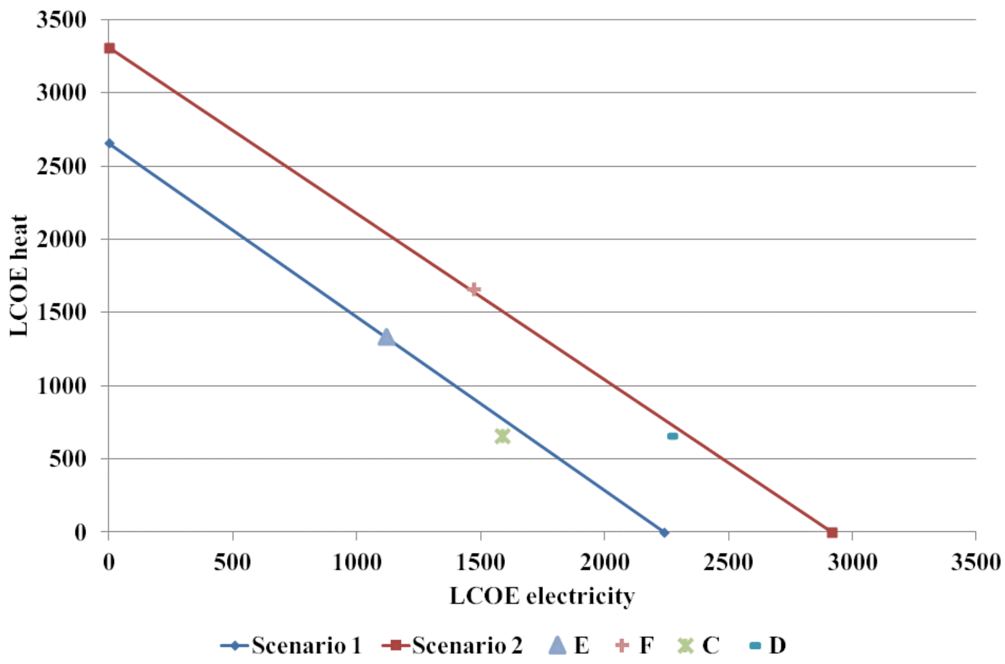

Figure 5 Ginter triangle for the Gas CCGT Small

Source: LCOE results

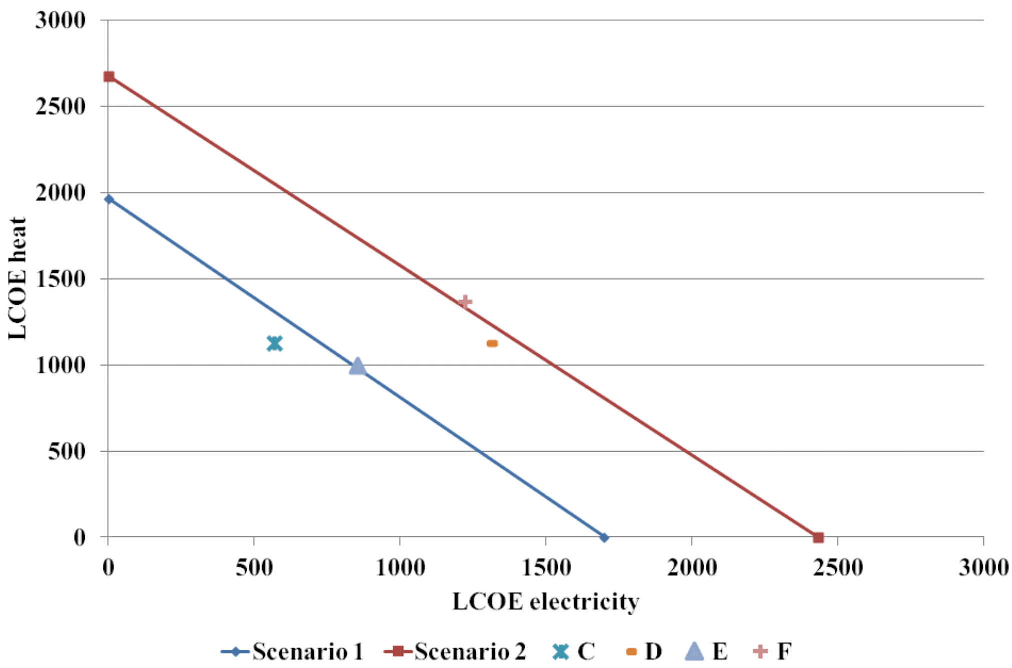

Figure 6 Ginter triangle for the Gas Turbine Large

Source: LCOE results

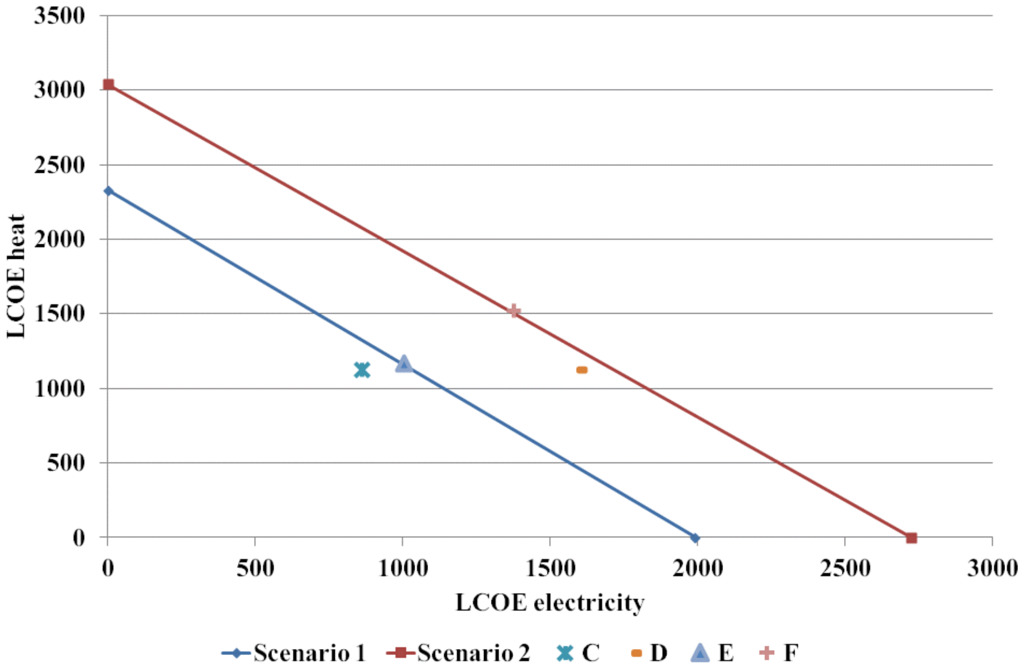

Figure 7 Ginter triangle for the Gas Turbine Small

Source: LCOE results

Figure 8 provides Ginter triangles for a black coal PCC generator. The two triangles coincide as the change in natural gas price for each scenario does not affect cost estimates for black coal fired generators. Importantly, the heat credit approach provides cost estimates (points C,D) close in value to the separation coefficients approach (points E, F).

It can be observed that LCOE estimates from the heat credit approach lie under the edge of the Ginter triangles. This can be interpreted as resulting from one of the following:

- application of heat credit values based on the assumed heat credit rate results in underestimation of total energy generation costs;
- application of 50% probability level for the LCOE estimation with Monte Carlo simulation results in overestimation of total generation costs.

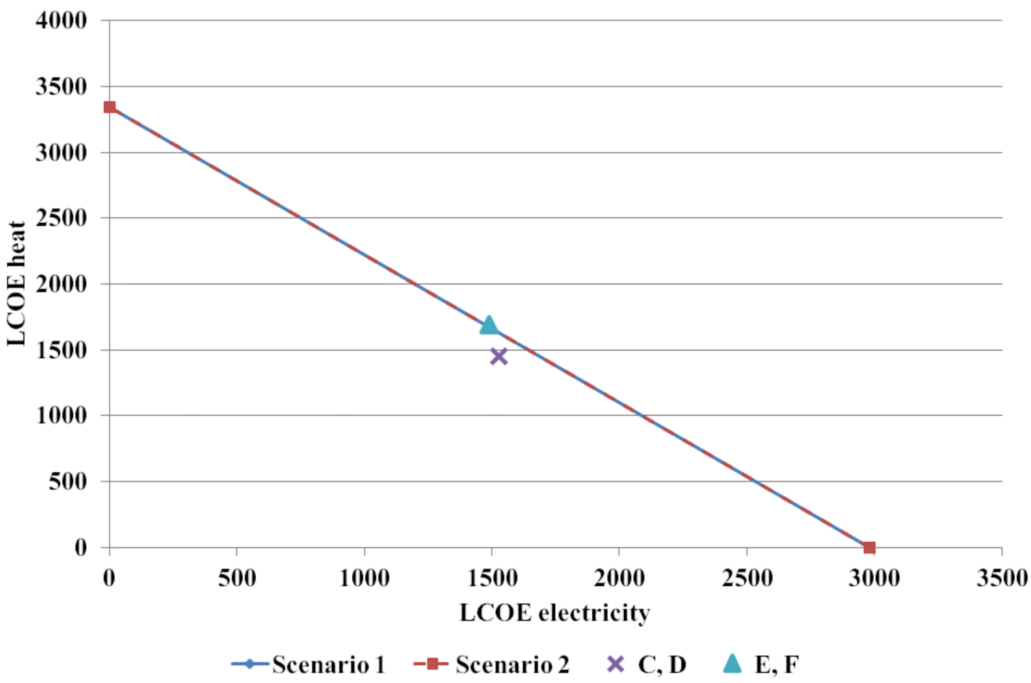

Figure 8 Ginter triangle for Black Coal PCC

Source: LCOE modelling results

The analysis of Ginter triangles with mapped LCOE estimates, obtained using different approaches, demonstrates the difference between estimates for some technology types and closeness for others. Although it cannot be concluded with certainty that one approach provides better estimates than the other, two principal advantages of the developed separation coefficient approach, developed in this study, have been demonstrated by the case study application.

- Although heat credit is a transparent approach for the electricity generation cost determination for CHP technologies, it doesn't allow us to draw conclusions on the generating costs for heat as a separate energy product. The heat credit rate value is also questionable. In contrast, the modified LCOE with the separation coefficients provides estimates based on generation costs for heat (rather than potential revenue from heat generation). As a result, obtained values can be considered as estimates of the LCOE for heat.
- The separation coefficients approach provides an adjustable tool for LCOE estimation and associated decision making. As compared to the heat credit approach, it allows us to reflect technology specific features in the cost estimates. Various sets of separation coefficients can be developed and applied. The set of separation coefficients adopted in this study is only one example utilizing this property of the modified LCOE model.

To further analyse the obtained results they need to be discussed in comparison with the findings of previous studies. This is provided in the next section.

4.5 Cost modelling outcomes in comparison with previous studies

A comparison of the obtained results with estimates sourced from a previous study (Bratanova, 2014) demonstrates that the LCOE for electricity for CHP generators is below estimates for the power only generators obtained previously across the technology types for Moscow regional conditions. CHP LCOE cost estimates for electricity substantially outperform generating costs for existing conventional generators in Scenario 1. More specifically, electricity generation cost estimates are two fold less for both small and large gas turbine CHP (1383 RUR/MWh and 1181 RUR/MWh) when compared to conventional gas fueled generators of small and large sizes (2791 RUR/MWh and 2473 RUR/MWh).

For Scenario 2 the CHP large gas turbine and large CCGT technology provide better cost performance than any other electricity generators including biomass which was shown to be a leader in the technology ranking in the Bratanova (2014) study (1918 RUR/MWh).

Overall, the applied separation coefficient approach within the modified LCOE model allows us to obtain comparable parameters for electricity generation costs for different technology types. Generally, CHP generators provide better LCOE estimates than electricity only generators. This suggests that CHP generators are cost-effective.

The obtained results from the modified LCOE model also need to be compared with international studies before recommendations can be made on the applicability and potential usefulness of the modified LCOE model for decision making in Russia. For this purpose the IEA study is considered (IEA and NEA 2010) with the estimates provided for power generation technologies in Russia (table 10).

Table 10 Comparison of the results with estimates from the international studies

Technology type	IEA study estimates (10% discount rate), RUR/MWh	Modified LCOE results (50% probability level), RUR/MWh
Black Coal PCC	1128	1515
Gas CCGT Large	1416	1247
Gas CCGT Small	1807	1475
Gas Turbine Large	1271	1225
Gas Turbine Small	1573	1377

Source: LCOE results, IEA study (2010)

The obtained LCOE estimates for CHP technology appear close to the estimates from the IEA study. The difference vary across the technology types from 4% (large gas turbine) to 26% (black coal PCC). The nature of this difference can be attributed to the different cost separation approaches applied as well as to the different financial assumptions used. However, the closeness of the estimates provides an argument to conclude that the LCOE modelling results obtained in this research are credible, and so too are the developed modifications to the standard LCOE model.

Having discussed the results of the LCOE modelling, it is important to acknowledge the limitations of the model construction, datasets and, consequently, research findings. The limitations of this study are associated with the limited data availability and uncertainty of the assumed parameters. Some cost variables were not available at the time of this research, including energy transportation costs (fuel transportation and transmission) and social and environmental costs. Improvement in the consistency and completeness of the data for the energy sector would imply more reliable, applicable and transparent results. Incorporation of environmental costs would improve the modelling results in the future research (Orlov, Grethe et al. 2013)

Heat consumption and associated generation is seasonal with no generation outside non-heating periods as compared to continuous electricity generation. The developed model doesn't allow for the incorporation of seasonality into the analysis. This limits the analysis, but could be overcome in future development of the modelling tool.

The selected technology types are defined only in general terms due to data limitations. Determination of specific parameters for the generating plants is therefore subject to the priorities and policies of the decision maker.

The method adopted in this paper for generating cost separation has an important limitation: it doesn't account for different values for the energy output (Mott MacDonald 2010). Specifically, it doesn't take into consideration that electricity is the most valuable energy output, it also ignores the fact that heat of different quality is characterised by different output temperature and pressure and has as a consequence has different values.

It is important to acknowledge, that interpretation of the obtained numerical estimates should be made with caution and with reference to the specific assumptions. This is applicable to the modified LCOE model as much as to any economic model which simplifies market and industry details and mechanisms (Paltsev 2014). Given the limitations of this study, interpretation of the results should be undertaken with care.

5. Conclusions and policy implications

This study suggests a modification to the LCOE model using separation coefficients and Monte Carlo simulation to determine cost of heat and electricity generation in the cycle of CHP generation. Overall, the developed LCOE model for the Moscow region in this context has demonstrated its capability to provide estimates and to provide a foundation for the selection of best performing generation technology types on the basis of generation cost.

The analysis of CHP generation for the Russian regional case study with the modified LCOE model leads to a number of important conclusions.

- Natural gas based CHP generators demonstrate better cost performance then black coal based technology across the considered scenarios and for electricity as well as heat generation. It implies that natural gas based CHP plants, and specifically those utilising gas turbines, provide robust low cost generation and could attract investment in the industry.
- A comparison of LCOE estimates for CHP electricity generation with estimates obtained for electricity-only generators in previous studies demonstrates better cost performance of CHP generation across the generation technology types. It suggests cost effectiveness of the CHP generation for Russian regions.

The obtained results form the basis of a recommendation to the regional government for further development of CHP as an energy alternative providing the most cost effective technology for energy generation among the considered technologies. This conclusion is supported by the scenario analysis outcomes. Even with nearly double natural gas prices (the second scenario), CHP gas-based plants maintained the leading position in the technology ranking for electricity generation.

Importantly, the suggested modified LCOE approach is capable of estimating not only generation cost parameters, but might be useful also to produce forecasts for the wholesale market. For the Moscow case study, this is especially important. A movement toward market based pricing in the wholesale electricity market hasn't resolved the issues with tariff determination, heat tariff system is also awaiting the proposed reforms. The modified LCOE, therefore, can provide a solution for the determination of tariffs based on economic efficiency, as well as for the strategic planning of energy sector development at regional and national levels.

At the same time the study demonstrates reliability and transparency of the methodological solution which ensures applicability of the modified LCOE to a wider range of cases including energy related projects in regions across Russia and for different technology and timeframes. Although regional specification of the assumed variables in the model implies that the obtained numerical estimates are only valid for the described regionally and technologically specific circumstances, the presented Moscow case study provides useful guidance for the implementation of decision support tools in other regions.

Generally, the application of different approaches to the separation of the heat and power generating costs within CHP plants remains a question for discussion. Several major approaches tested in the LCOE application identified important differences in the obtained estimates. Although neither approach can claim to be unambiguously preferred, the study has demonstrated the applicability of the developed separation coefficients approach based on Ginter triangles for the analysis of CHP generation costs. The modified LCOE model appeared more flexible for incorporation of technology specific features as compared to the widely used heat credit approach. However, determination of the basis for separation coefficients or a point along the Ginter triangle hypotenuse is a subject for future research.

Overall, the security of supply, infrastructure development, competitiveness and energy efficiency improvement in Russia requires public and private investment in all sectors of the energy system as well as well-developed public management and regulatory systems. The modified LCOE provides one of a range of possible methodological solutions to support decision making for energy sector management in Russia, which considers heat as a separate and valuable product of cogeneration. Reforming the heating sector in Russia will require price liberalisation and a gradual shift to market based pricing. The cost competitiveness of the generators will then play a crucial role in the determination of the market structure and investment decisions of market participants. However, a comprehensive policy will also be required to insure attrition of investment in the industry, the integration with energy efficiency policy and effective transformation of the national and regional energy systems.

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