E.ON Energy Research Center
FCN | Institute for Future Energy Consumer Needs and Behavior

FCN Working Paper No. 12/2010

Investment in New Power Generation under Uncertainty: Benefits of CHP vs Condensing Plants in a Copula-Based Analysis

Günther Westner and Reinhard Madlener

September 2010

Institute for Future Energy Consumer Needs and Behavior (FCN)

Faculty of Business and Economics / E.ON ERC

RWTH AACHEN UNIVERSITY

FCN Working Paper No. 12/2010

Investment in New Power Generation under Uncertainty: Benefits of CHP vs Condensing Plants in a Copula-Based Analysis

September 2010

Authors' addresses:

Günther Westner
E.ON Energy Projects GmbH
Arnulfstrasse 56
80335 Munich, Germany
E-mail: guenther.westner@eon-energie.com

Reinhard Madlener
Institute for Future Energy Consumer Needs and Behavior (FCN)
Faculty of Business and Economics / E.ON Energy Research Center
RWTH Aachen University
Mathieustrasse 6
52074 Aachen, Germany
E-mail: rmadlener@eonerc.rwth-aachen.de

Publisher: Prof. Dr. Reinhard Madlener
Chair of Energy Economics and Management
Director, Institute for Future Energy Consumer Needs and Behavior (FCN)
E.ON Energy Research Center (E.ON ERC)
RWTH Aachen University
Mathieustrasse 6, 52074 Aachen, Germany
Phone: +49 (0) 241-80 49820
Fax: +49 (0) 241-80 49829
Web: www.eonerc.rwth-aachen.de/fcn
E-mail: post_fcn@eonerc.rwth-aachen.de

Investment in new power generation under uncertainty: Benefits of CHP vs. condensing plants in a copula-based analysis

Günther Westner [a] and Reinhard Madlener [b,*]

[a] E.ON Energy Projects GmbH[**], Arnulfstrasse 56, 80335 Munich, Germany

[b] Institute for Future Energy Consumer Needs and Behavior (FCN), Faculty of Business and Economics / E.ON Energy Research Center, RWTH Aachen University, Mathieustrasse 6, 52074 Aachen, Germany

September 2010

Abstract

In this paper, we apply a spread-based real options approach to analyze the decision-making problem of an investor who has the choice between an irreversible investment in a condensing power plant without heat utilization and a plant with combined heat-and-power (CHP) generation. Our investigation focuses on large-scale fossil-fueled generation technologies and is based on a stochastic model that uses copula functions to provide the input parameter of the real options model. We define the aggregated annual spread as assessment criteria for our investigation since it contains all relevant volatile input parameters that have an impact on the evaluation of investment decisions. We show that the specific characteristics of CHP plants, such as additional revenues from heat sales, promotion schemes, specific operational features, and a beneficial allocation of CO_2 allowances, have a significant impact on the option value and therefore on the optimal timing for investment. For the two fossil-fueled CHP technologies investigated (combined-cycle gas turbine and steam turbine), we conclude from our analysis that a high share of CHP generation reduces the risk exposure for the investor. The maximal possible CHP generation depends significantly on the local heat demand in the surroundings of the power plant. Considering this, the size of the heat sink available could gain more relevance in the future selection process of sites for new large-scale fossil power plants.

Key words: Combined heat and power; Real options; Investment under uncertainty, Copula function

JEL Classification Nos.: C46; C61; D81; Q41

* Corresponding author. Tel. +49 241 80 49 820, Fax. +49 241 80 49 829; E-mail: rmadlener@eonerc.rwth-aachen.de (R. Madlener).

** Please note that all statements made in this article are those from the authors and do not necessarily reflect the views of E.ON Energy Projects GmbH.

1 Introduction

Fossil-fueled power plants will play an important role in the future European power generation portfolio even if EU member states continue to tighten the reduction targets for greenhouse gas emissions and to boost the usage of renewable energy sources. Currently, there are more than 8 GW of coal-fired generation capacity under construction across, Europe and further investments in coal-fired and gas-fired generation technology are planned in the coming years to cover the growing demand for power (IEA, 2008a; Pahle, 2010). These new investments will likely dominate the European generation portfolio far beyond the year 2030. However, high investment costs, long payback periods of irreversible investments in new power plants, commodity price variability in liberalized power markets, and regulatory uncertainty bear significant risks for the investing utilities. As a consequence, some utilities have already postponed or even canceled planned investments in new fossil power plants.

The power plant technology adopted has a significant impact on the risk exposure associated with new investments in generation infrastructure. In this paper, we put our focus on the question of whether combined heat and power (CHP) generation can contribute towards the reduction of risks resulting from commodity price variability and risks related to, say, changes in regulation, or to climate policy. CHP is one of the most effective means for saving primary energy and reducing greenhouse gas emissions (IEA, 2008b; Blok and Turkenburg, 1994). Due to these benefits, many EU member states promote CHP generation to accelerate the dissemination of CHP technologies (Westner and Madlener, 2009). Specific characteristics, such as additional revenues from heat sales, specific operational features, and a beneficial allocation of CO_2 allowances, can, in addition to the guaranteed governmental CHP promotion e.g. by means of feed-in tariffs, contribute towards the reduction of risk exposure of CHP generation in comparison to condensing plants with power-only generation.

Investments in new large-scale power plants imply high investment costs and long payback periods, and thus bear significant risks for the investing utility. The risk exposure depends on the development of commodity prices in liberalized energy markets as well as on political and regulatory uncertainties, and hence has serious impact on the investment decision. Up to now, the benefits of CHP generation in the context of investment decisions in large-scale fossil power plants have not been investigated sufficiently. In our research, we apply a model of decision-making under uncertainty using a real options approach (Dixit and Pindyck, 1994;

Trigeorgis, 1996). Specifically, we compare the risk exposure of energy companies having the opportunity to invest either in a conventional condensing plant or a plant with CHP generation. The real options methodology has already been widely applied in the context of investment decisions in the electricity sector (e.g. Rothwell, 2006; Wickart and Madlener, 2007; Fleten and Näsäkkälä, 2010) and provides a powerful tool to quantify investment risk (Copeland and Antikarov, 2001). In order to evaluate different power generation technologies, we take the market conditions and regulatory framework established in Germany as the basis for our analysis. Due to the commitment of the German government and a beneficial promotion scheme, the conditions for CHP generation in Germany are more favorable than compared to those in other European countries (Westner and Madlener, 2009).

This paper is structured as follows. In section 2, we first provide a concise overview of the relevant literature on real options theory applied to investment decisions for new power generation assets. Section 3 describes the specific characteristics of CHP in comparison to other generation technologies. The input parameters used in our model are described in section 4. Section 5 defines the structure of the real options model applied. In section 6, we present and discuss the results obtained. Section 7 concludes.

2 Review of related literature

Options theory was originally developed in the 1970s (Black and Scholes, 1973; Merton, 1973) to evaluate financial options, but economists realized very soon that option pricing could also provide important insights into decision-making on capital investments. Therefore, with reference to the real assets involved, the term “real options” was established. First applications of real options theory on investment decisions were made by McDonald and Siegel (1986), Pindyck (1988, 1991, 1993), and Dixit and Pindyck (1994). During the last few years, in a number of studies, real options theory has also been applied to decision-making problems in the energy sector and here especially for investments in new power generation infrastructures. In this section, we provide a chronological overview of the most recent publications that apply real options theory in the context of power generation. We also review some of the relevant literature related to investment decisions in CHP generation.

Murto and Nese (2003) focus on the optimal timing and the optimal technology choice for investments in power production technologies. They put their focus on uncertainties arising from input price variations, and investigate the impact on investments in fossil-fueled and biomass-fired power plants. By applying a real options model with stochastic input prices, they show that prices for fossil fuels are the main driver for investment timing and technology choice. Sundberg and Sjödin (2003) in their research, consider how investment decisions in CHP plants are influenced by the liberalization of the European electricity markets. Their investigation focuses specifically on a co-operation between a paper mill and a municipal utility. With an economic simulation model that is calibrated for the market conditions in Sweden, they show that the optimal technology choice is strongly influenced by the returns required by the investor. Ishii and Yan (2004) investigate how the investment behavior of firms operating in the U.S. power sector depends on uncertainties in the regulatory framework. They find evidence that regulatory uncertainty creates substantial option values, which initiate utilities to delay their investment decisions in order to gather more information and assurance regarding future regulatory change. They compare the results of their real options model with corresponding estimates of two alternative models based on net present value (NPV) and forward-looking (FWL) expectations. Hlouskova et al. (2005) consider the commitment problem of an electricity producing turbine in the liberalized German power market and derive profit-maximizing commitment decisions. They model the price uncertainty with a mean-reverting process including jumps and time-varying means to account for seasonality. The model is also applied to compute risk profiles of generation assets for risk management purposes. Näsäkkäla and Fleten (2005) apply real options theory to gas-fired power plants. They distinguish between gas-fired baseload and peakload plants. Their model is based on the spark spread, defined as the difference between the price of electricity and the cost of gas used for power generation. They come to the conclusion that an increase in the variability of spark spreads has an ambiguous effect on the investment decision and increases the profitability of peakload plants. Roques and Savva (2006) study the effect of price cap regulation on investments in new generation capacity in an oligopolistic market. In their continuous time model, they use stochastic demand volatility as an input variable for a real options evaluation. They show that there exists an optimal price cap that maximizes investment incentives, and that errors in the choice of the price cap can have detrimental consequences. Rothwell (2006) uses a real options approach based on NPVs to determine the risk premium associated with net revenue uncertainty of new nuclear power plants in Texas. The author concludes that it is unlikely that there will be new orders for nuclear power plants in deregulated electricity markets at the nuclear power plant prices quoted, unless there are either dramatic changes in the CO_2 mitigation policy or dramatic increases in fossil fuel prices. Blyth et al. (2007) analyze the effect of uncertainties in future climate policy on investment decisions in new power plants. In their model, which is based on real options theory, they treat future climate policy as an external risk factor. The study analyzes investment options in coal-fired and gas-fired power plants in combination with carbon capture and storage (CCS) technologies. The authors conclude that the closer in time the change in policy is, the greater the policy risk and the impact on the investment decision are. In this respect, retrofit of CCS for coal plants can be used as a hedge against higher-than-expected future carbon prices. Wickart and Madlener (2007) investigate with their real options model the decision-making problem under uncertainty of an industrial firm, which is considering investing either in CHP generation or in heat-only production. Their model includes the main economic and technological variables as well as the uncertainty inherent in volatile commodity prices. According to their findings, simplistic NPV calculation can be misleading when estimating economic CHP potentials. Also, they find that energy market regulation might have a significant impact on the economics of CHP potentials by altering price volatilities. Kumbaroğlu et al. (2008) analyze diffusion prospects of new renewable power generation technologies by applying a dynamic programing model based on real options theory. They include learning curve information on renewable power generation technologies and come to the conclusion that the flexibility to delay irreversible investments can profoundly affect the diffusion prospects of renewable power generation technologies. Governmental promotion accelerates learning effects and, therefore, leads to cost declines for renewable energy technologies and thus to faster diffusion and more emission reduction. Yang et al. (2008) focus on the evaluation of investments in the power sector with respect to uncertainties in climate policy. They use real options theory to investigate investments in different generation technologies, including gas, coal, and nuclear generation, and conclude that climate policy risks increase before important climate policy events and vary according to the technology chosen. Investor risks can be reduced by implementing long-term rather than short-term climate change policy frameworks. Siddiqui and Maribu (2009) develop and apply a real options model for microgrids that consist of small-scale distributed generation and CHP applications to meet local energy loads. In order to reduce the risk exposure, they investigate various investment strategies and come to the conclusion that a direct investment strategy in microgrids is more beneficial for low levels of gas price volatility, whereas a sequential strategy is preferable in the case of high price volatility. Fleten and Näsäkkälä (2010) consider investments in new gas-fired power plants in liberalized energy markets with volatile electricity and natural gas prices. In their investigation, they derive the value of operating flexibility, and find thresholds for energy prices that are optimal for entering into investments. They come to the conclusion that operating flexibility and the abandonment option interact in a way that their joint value is less than their separate values, and that operating flexibility has significant effects on the decision to build a plant.

As our review shows, the existing literature provides several examples of application of real options theory and decision-making under uncertainty in the context of new investments in power generation technologies. Table 1 summarizes chronologically the latest research activities in this area.

Table1: Chronological summary of selected literature on applying real options theory to investment decisions in the energy sector

Study	Scope of research	Research focus	Data	Model(s) used	Main findings, conclusions
Murto and Nese (2002)	Investment decision between fossil- and biomass-fueled power plants	Investment timing and optimal technology choice for energy investments	Stylized; Numerical example based on market data from Nordpool	Dynamic real options model with stochastic input prices	Commodity price development of fossil fuels has a significant impact on investment timing and technology choice of new power plants.
Sundberg and Sjödin (2003)	Investment decisions in CHP plants	Optimization potential of a co-operation between a paper mill and a municipal utility	Commodity market prices in Sweden (1997-2001)	Economic simulation model MODEST (model for optimization of dynamic energy systems)	A co-operation between the paper mill and a municipal utility increases the cost-effectiveness by 7-11%. The chosen CHP technology affects the returns of both actors.
Ishii and Yan (2004)	Investment under regulatory uncertainty	Investment behaviour of firms operating in the U.S. power sector under regulatory uncertainty	Investments in the U.S. power generation sector (1996-2000)	Real options model, expected net present value (NPV) and forward-looking (FWL) model	Regulatory uncertainty creates a substantial option value that leads firms to delay investment decisions
Hlouskova et al. (2005)	Investment in an electricity producing turbine	Profit-maximizing investment decisions for power plants	Hourly electricity prices at the LPX spot market from (2000-2003)	Real options model, price uncertainty is captured by a mean reverting process with jumps	Real options theory can be applied in the context of short-term optimization and used to derive the value of an electricity producing turbine
Näsäkkäla and Fleten (2005)	Investments in gas-fired power plants	Flexibility in technology choice for investments in new power plants	Data from electricity and gas forward markets in Norway (Jan 2001 - Jan 2004)	Real options model, allowing for mean reversion in short-term variations	An increase in the variability of spark spreads impacts the investment decision and increases the attractiveness of peakload plants.

(Table 1 – cont.)

Roques and Savva (2006)	Investments in a regulated power market	Effects of price cap regulation on investments in an oligopolistic industry; focus on demand uncertainty	Stylized	Real options approach based on stochastic demand volatility	Price cap regulation depends critically on demand volatility. Errors in the choice of the price cap can have detrimental consequences on investments and average prices.
Rothwell (2006)	Investments in new nuclear power plants	Determination of risk-adjusted costs of capital for new nuclear power plants	Electricity market data from Texas-ERCOT (1990-2003)	Real options approach based on NPV calculation	Specific investment costs of about $ 1,200 per kW_{el} could trigger new orders in nuclear power plants. New investments in nuclear power plants require dramatic changes to the commodity price level or changes in regulation.
Blyth et al. (2007)	Investments under uncertain climate change policy	Quantification of regulatory risks for coal- and gas-fired power plants and CCS technologies	Stylized	Dynamic programing model based on the real options approach	The closer the change in policy, the greater the policy risk and the impact on the investment decision. Retrofit of CCS for coal plants is a hedge against higher-than-expected future carbon prices.
Wickart and Madlener (2007)	Energy supply related investment decision of industrial companies	Economic modeling of two different technologies: CHP vs. heat-only production	Stylized	Stochastic model based on real options theory	Pure NPV calculation is misleading when estimating economic CHP potentials. Price volatility of commodities has an impact on the economic attractiveness of CHP potentials.
Kumbaroğlu et al. (2008)	Diffusion of new renewable power generation technologies	Integration of learning curves for renewable energy technologies	Empirical analysis based on data on the Turkish electricity supply industry	Dynamic programing model based on the real options approach	Governmental promotion accelerates the diffusion of renewable energy resources, enables learning curve effects and, therefore, leads to cost declines.
Yang et al. (2008)	Investments in the power sector with respect on uncertainty in future climate policy	Impact of climate policy on the technology choice of private investors	Stylized	Dynamic programing model based on the real options approach	Climate change policy risks depend on the technology chosen and increase before a climate policy event. The risks can be reduced by implementing long-term rather than short-term climate change policy frameworks.
Siddiqui and Maribu (2009)	Investments in distributed generation	Economic evaluation of different kinds of investment strategies: direct vs. sequential investments	Case studies from several sites in the San Francisco area	Dynamic programing model based on the real options approach	For a low level of gas price volatility it is preferable to pursue a direct investment strategy. A sequential investment strategy is better in the case of a high gas price volatility.
Fleten and Näsäkkälä (2010)	Investments in gas-fired power plants	Economic evaluation of operating flexibility and abandonment option	Commodity prices derived from Norwegian commodity markets (Jan 2001 - Jan 2004)	Two-factor model to process power and gas prices	Operating flexibility and the abandonment option interact in a way that their joint value is less than their separate values. Operating flexibility can have a significant effect on the building decision.

Source: Own compilation

3 Specific characteristics of CHP in comparison to other power generation technologies

Economic evaluation of CHP generation assets contrasts significantly with that of conventional power generation technologies or renewable energy sources. The evaluation further depends on the regulatory framework with respect to CHP in the country considered, and it influences investment decisions as well as the operation of CHP plants. In Germany, the country focused on in our investigation, the most significant differences between CHP and conventional power plants are related to additional revenues from heat sales, revenues through governmental CHP promotion, specific operational features and a beneficial allocation of CO_2 emission allowances. In the following, we put the focus on these four specific characteristics of CHP generation and analyze qualitatively their impact on the investment decision.

3.1 Additional revenues from heat sales

In contrast to condensing plants for power-only generation, CHP plants also produce heat as a secondary product. The additional revenues through heat sales can contribute towards reducing the risk exposure of the total investment in CHP technologies. The degree of risk reduction depends on the impact of heat revenues on the volatility of the total plant revenues, and is influenced by the correlation between heat revenues and commodity prices for power and fuels. In order to analyze the effects of additional revenues from heat sales in the applied model, we need to quantify volume and volatility of heat revenues. Due to the fact that there is no transparent market price for heat available, it is typically impossible to derive heat prices and volatilities from historical market data. CHP-related literature describes several approaches to allocating fuel consumption or fuel cost between power and heat production (see Dittmann et al., 2009). The approach adopted for our investigation is to define the price for heat generically via the avoided cost of alternative heat production. Specifically, we assume that an alternative isolated heat production is based on gas-fired heat boilers (efficiency of 90%) and that the fuel costs are equal to the revenues through heat production via CHP (cf. section 4.1). The volatility of the heat price is highly correlated with the fuel price; therefore, we take the same standard deviation for the heat revenues as for natural gas. A detailed consideration of investment cost for separate heat-only production is neglected for simplicity.

3.2 CHP promotion

In many European countries, CHP generation receives governmental promotion (see also Westner and Madlener, 2009, and references therein). In our research, we focus on the situation in Germany, where CHP promotion is guaranteed through the German CHP Act 2008 (KWK-Gesetz, 2008). According to this law, electrical power from CHP plants receive guaranteed feed-in tariffs on top of the normal price for power. The feed-in tariffs are paid by the grid operator who allocates the costs of the promotion between all power consumers, similar to the mechanism for renewable energy sources (see EEG, 2008). The subsidy level and the duration of promotion depend on the size (defined via the electrical net capacity) and the kind of CHP generation. For investors in new CHP plants, the governmental promotion states a guaranteed additional income for each Megawatt-hour produced. During the promotion period, the revenues of CHP plants, therefore, depend not solely on volatile commodity prices, but also on fixed revenues from CHP promotion. This reduces the volatility of CHP revenues in relation to the total revenues obtained, and affects the option value of the investment decision in CHP generation.

3.3 Operation mode of CHP plants

In principle, the operation mode of power plants can be differentiated between power-controlled and heat-controlled operation. The utilization of power-controlled plants is defined by the market price of electrical power. The plant is in operation if the variable costs, which are mainly determined by fuel costs and variable operational costs, are below the market price. The plant is out of operation if variable costs are beyond the current market price for electrical power. As a consequence, the utilization of power-controlled plants largely depends on the variable operating costs and is mainly determined by the generation technology chosen. Generation technologies with comparably low variable generation costs, such as hydro or nuclear, can reach a high utilization of up to 8,000 hours per annum. This is different for other generation technologies with variable generation costs close to the market price level (marginal plants). For these technologies, such as coal-fired or gas-fired plants, the number of full-load hours reached depends to a high degree on the level and volatility of market prices for electrical power.

The utilization of heat-controlled CHP plants is determined by heat demand. In times of insufficient heat demand, the plant is not running and hence also generates no electrical power output. The size of heat-controlled CHP plants is usually dimensioned according to the constant heat sink (e. g. for district heating) in the surroundings of the plant site. Depending on the chosen technology and the kind of application, the utilization of CHP plants operated in the heat-control mode lies between 4,500 and 8,000 full-load hours, and depends less on the price level for electrical power than on the characteristics of heat utilization.

The operation mode and, as a consequence, the plant utilization have a significant impact on the economics of investments in new power generation. As the characteristics of utilization differ significantly between power-controlled and heat-controlled plants, we need to consider this aspect in our investigation. The more volatile the utilization is, the more volatile the revenues are and the higher the option value of the plant is.

3.4 Allocation of CO_2 emission allowances

In many European countries, CHP generation receives a beneficial allocation of CO_2 emission allowances. In Germany, the national allocation plan (BMU, 2006) for the second trading period from 2008 to 2012 guarantees CHP plants a privileged allocation of free allowances according to the double benchmark principle[1]. As a consequence, CHP plants can in some cases even receive more allowances than used to cover their own emissions, and can gain additional revenues through selling the surplus of freely allocated allowances to the market. Fossil-fired condensing power plants without heat utilization receive in the current trading period an allocation that is, due to the applied reduction factor for power production, usually not sufficient to cover their emissions.

In the next trading period from 2013 onwards, the allocation mechanism of free CO_2 allowances will be modified fundamentally. Up to now, the final allocation rules and benchmarks for the next period are still under discussion, but the EU Directive 2009/29/EC (EU, 2009) already states some principles for the allocation of certificates in the post-2012 period. According to the directive, full auctioning will be established for emissions from electrical power generation, including CHP. The free allocation of certificates for heat production is expected to remain in place. This means that it is very likely that from 2013

[1] According to this principle, CHP plants receive CO_2 allowances for the power produced and additional allowances for heat production.

onwards, the present beneficial allocation for CHP according to the double benchmark principle will be canceled, but it is likely that a significant advantage for CHP will remain in comparison to fossil-fired condensing plants, due to the continuing free allocation for heat. In our investigation, we include the beneficial treatment of CHP generation concerning allocation of emission allowances, quantify the effects, and derive the impact on the option value of CHP investments in comparison to conventional fossil plants.

4 Model assumptions and definition of assessment criteria

In this section, we describe the input parameters of our model and define the aggregated annual spread as assessment criteria for the subsequent investigation of various generation technologies.

4.1 Input parameter

The input criteria of our investigation are technical parameters, historical commodity prices, and the legal framework for CHP promotion in Germany. We use these criteria in our model to quantify the option values of different generation technologies. For a recent study of the relative attractiveness of CHP generation in selected European countries see Westner and Madlener (2009).

4.1.1 Technical parameter of the power plants

In our investigation, we put the focus on the comparison of investment decisions in condensing plants and investments in CHP plants. This comparison is based on two standard fossil-based generation technologies: hard-coal-fired steam turbine (ST) with 800 MW_{el} and combined-cycle gas turbine (CCGT) with 400 MW_{el}. The chosen plant size, characterized by the electrical capacity, is typical for new power plants of the respective technology. Table 2 contains further assumptions concerning the technical parameters.

Table 2: Technical input parameters used in the model

		Hard-coal ST technology		CCGT technology	
		Condensing plant	CHP plant	Condensing plant	CHP plant
Fuel type		hard coal	hard coal	natural gas	natural gas
Operation mode		power control	power control	power control	heat control
Capacity (electrical)	MW_{el}	800	800	400	400
Plant lifetime	A	40	40	30	30
Power efficiency		0.45	0.42	0.60	0.45
Heat efficiency		-	0.18	-	0.35
Global efficiency (degree of fuel utilization)		0.45	0.60	0.60	0.80
Efficiency of alternative heat production		-	0.90	-	0.90
CO_2 emission factor	g CO_2/kWh_{el}	800	800	380	380
CO_2 benchmark power	g CO_2/kWh_{el}	750	750	365	365
CO_2 benchmark heat	g CO_2/kWh_{th}	-	345	-	225
Promotion for CHP power generation	€/MWh_{el}	-	15	-	15

Source: Operational data derived from existing E.ON plants

We assume that the investigated condensing plants (for both fuel types) are operated in the power-control mode. For the coal-fired CHP plant, we also assume that it is operated in this mode. The defined heat efficiency of this plant lies at about 18%, which is a typical value for large coal-fired plants with heat extraction in Germany. This assumption implies that the lion’s share of the heat production is not utilized and that the useful heat demand can be covered even if the plant is operating below its maximum power output. This provides some operational flexibility and enables operators to run coal-fired CHP plants also in the power-control mode. Later in our investigation, we increase the degree of heat efficiency and describe the effect on the option value. The gas-fired CCGT-CHP plant is characterized by a lower capacity and high heat efficiency of 35%.. Such plants are often used to supply large consumers, such as industrial factories, with a high and constant power and heat demand. These plants are typically operated in the heat-control mode, which we also assume for the CCGT-CHP plant in our investigation. All other parameters as given in Table 2 are typical values for the respective technologies, derived from existing plants in Germany.

4.1.2 Commodity price assumptions

The commodity prices used in our model are taken from the commodity markets in Germany. As input parameters we use the historical commodity prices, as given in Table 3. The price for heat is calculated on the basis of a gas-fired heat boiler with an efficiency of 90%.

Table 3: Characteristics of commodity prices used for MVP investigation

Price variable	Periodicity	Time period	μ	σ
Power price [a]	Daily	Oct 2007 - Sep 2009	54.71 €/MWh_{el}	21.49 €/MWh_{el}
Fuel price coal [b]	Daily	Oct 2007 - Sep 2009	10.25 €/MWh_{th}	2.10 €/MWh_{th}
Fuel price gas [c]	Daily	Oct 2007 - Sep 2009	20.09 €/MWh_{th}	6.80 €/MWh_{th}
CO_2 allowances [d]	Daily	Oct 2007 - Sep 2009	16.21 €/t CO_2	8.11 €/t CO_2
Heat price [e]	Daily	Oct 2007 - Sep 2009	22.32 €/MWh_{th}	6.80 €/MWh_{th}

Sources: [a] EEX Price Index: Phelix Day Base, [b] API#2-Index: ARA Quarterly Futures Price, [c] EEX Gas Spot Market EGT, [d] CO_2 Allowance Price Phase 2, [e] Calculated on the basis of a gas-fired boiler with an efficiency of 90%.

4.1.3 Promotion of CHP in Germany

The new German CHP Act 2008 (KWK-Gesetz, 2008), that entered into force on January 1, 2009, has significantly improved the conditions for CHP generation in Germany. According to this law, plants receive a guaranteed feed-in tariff on top of the price for the produced power. The subsidy level, as shown in Table 4, depends on the size of the plant, which is defined by the electrical net capacity.

Table 4: Promotion of CHP by the 2009 German CHP Act

Plant size	Remuneration
≤ 50 kW_{el}	5.11 ct/kWh for the duration of 10 years, no degression
≤ 2 MW_{el}	2.1 ct/kWh for the duration of 6 years or a maximum of 30,000 full-load hours 5.11 ct/kWh for the first 50 kW
> 2 MW_{el}	1.5 ct/kWh for the duration of 6 years or a maximum of 30,000 full-load hours Exception industrial applications: Duration only 4 years or a maximum 30,000 full-load hours 2.1 ct/kWh for the first 2 MW, 5.11 ct/kWh for the first 50 kW

Source: KWK-Gesetz (2008).

4.2 Calculation of the aggregated annual spread

We take the aggregated annual spread (*AAS*), which is the result of the convolution of the specific spread (*S*) and the power utilization of the plant (*U*), as criteria for the subsequent assessment of various generation technologies. The AAS is described by a cumulative distribution function. It can be considered as the major source of uncertainty for investments in new power plants. In this section, we first define the specific spread and the plant utilization, and than derive the distribution of the AAS by application of two alternative methods: correlation coefficients and copula functions.

4.2.1 Specific spread

The specific spread (*S*) per MWh is the difference between the price of the output (electrical power) and the costs of the input factors (e.g. fuels) or, in other words, the specific spread is the contribution margin that a plant operator earns for converting fuels into electrical power. We also consider the costs of CO_2 emissions and take the so-called “clean” spreads for our investigation. The spread of coal-fired plants is called “clean dark spread”, the spread of gas-fired plants “clean spark spread”. The specific spreads of condensing power plants, S_{Cond}, are defined as the difference between revenues and variable costs of power generation:

$$S_{Cond} = P_E - \frac{C_F}{\eta_{el}} - (\lambda_F - \pi_P) C_{CO2} \ , \qquad (1)$$

where S_{Cond} is the specific spread of a condensing plant in € per MWh of produced power, P_E is the market price of power in €/MWh, C_F denotes the fuel costs in €/MWh$_{th}$ and η_{el} the electrical efficiency of the condensing plant. λ_F denotes the CO_2 emission factor of the fuel used and π_P is the free allocation of CO_2 certificates for electrical power, both expressed in tons of CO_2 per MWh. C_{CO2} is the market price of CO_2 allowances in € per t of CO_2.

The specific spread of CHP plants additionally includes CHP promotion received and revenues through heat sales. The specific spread of a CHP plant (S_{CHP}) is defined as:

$$S_{CHP} = P_E + R_H + P_{CHP} - \frac{C_F}{\eta_{el}} - (\lambda_F - \pi_P - \pi_H) C_{CO2} \ , \qquad (2)$$

where R_H represents the additional revenues through heat sales and P_{CHP} represents the governmental promotion for CHP generation (both in €/MWh). The additional revenues through heat sales are related to the power generation of the CHP plant. In addition to the free allocation of CO_2 allowances for power (π_P), CHP receives further free allowances for heat (π_H) according to the double benchmark principle. Both allowances are calculated in tons of CO_2 per MWh.

Note that the specific spread S_i of a generation technology can be both positive and negative, and that it is affected by the development of prices of electricity, fuel, and CO_2 allowances in competitive commodity markets. Based on the historical commodity prices, as described in Table 3, we derive the characteristic parameters of the specific spreads in Germany during the time period October 1, 2007 till September 30, 2009. Figure 1 shows the historic development of the specific spread. The figure illustrates that for the CCGT technology (in comparison to coal-fired ST) the deviation between the specific spreads of CHP and condensing plants is more significant. This is caused by the effect that CCGT plants, due to their higher specific heat efficiency (per MWh), generate higher revenues through heat sales and CHP promotion. Table 5 contains the means (μ_i) and the standard deviations (σ_i) of the specific spread i for the four defined generation technologies subject to our investigation. The historical development of the specific spread shows a characteristic that can best be described by a normal distribution.

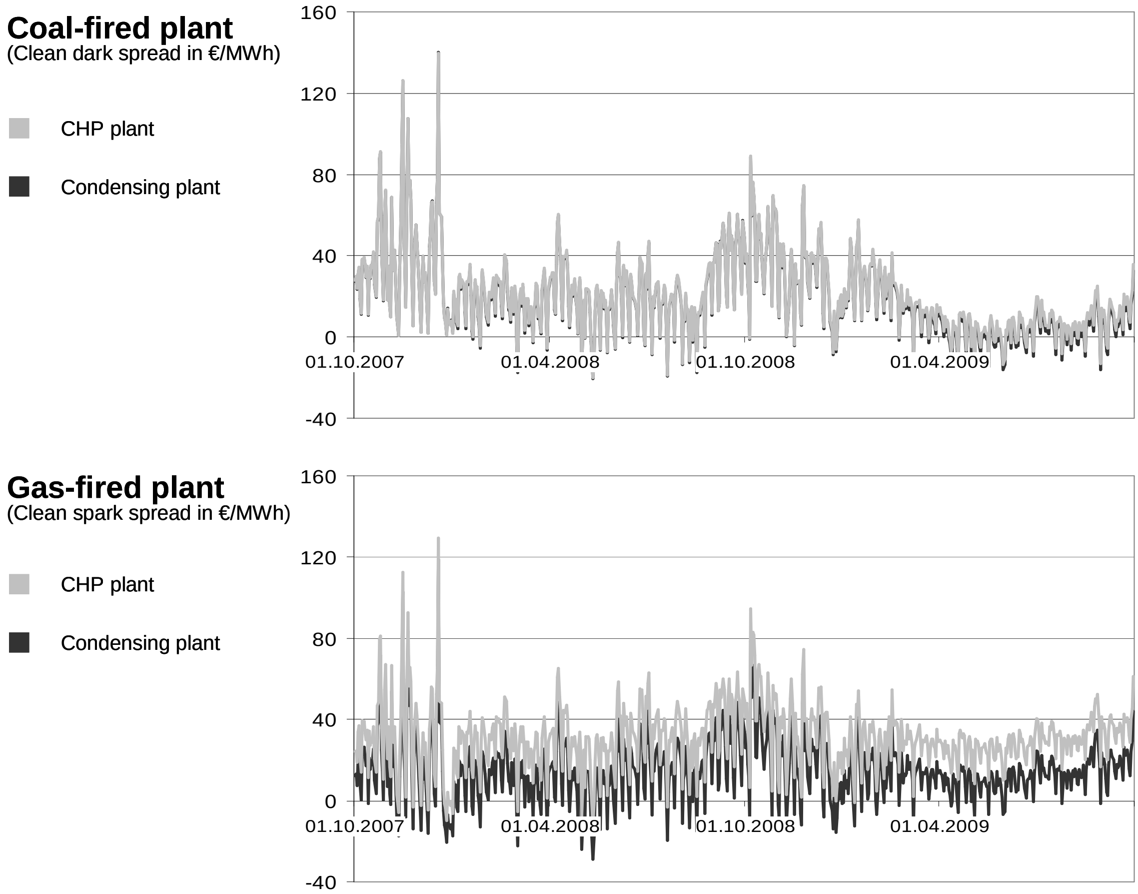


Figure 1: Development of the specific spreads from October 1, 2007 to September 30, 2009

Source: Own calculation, based on equation (1) and (2) with input parameter obtained in Table 3

Table 5: Characteristics of the specific spread for various generation technologies (observations over time period October 1, 2007 to September 30, 2009)

	Coal-fired plant (Clean dark spread in €/MWh)			**Gas-fired plant** (Clean spark spread in €/MWh)		
Technology	μ	σ	Probability distribution	μ	σ	Probability Distribution
Condensing plant	19.8	27.0	normal	15.6	29.8	Normal
CHP plant	21.0	24.9	normal	31.1	23.8	Normal

Source: Own calculation, based on Eqs. (1) and (2) with input parameter obtained in Table 3

4.2.2 Utilization of power plants

The plant utilization is the second important input parameter that has a significant impact on the economics of power plants and, therefore, needs to be considered in our model. As already mentioned in section 3, the utilization depends to a large extent on the operation mode of the plant and varies significantly between the power-control mode, which is characteristic of condensing plants, and the heat-control mode, which is typical of many CHP applications.

The utilization of power-controlled plants depends on the price level at the wholesale market for electrical power in relation to the variable generation costs of the plant. If the variable generation costs are below the power price, the plant produces electrical power; otherwise, the plant is out of operation (ignoring ramp-up and shut-down costs and technical restrictions). As a consequence for power-controlled plants, the specific spread and the utilization are not independent.

The power utilization of heat-controlled CHP plants depends on the heat demand. If the heat demand is constant over the entire year, e.g. in CHP plants used for industrial applications, the power utilization per annum can reach up to 8,000 hours with a comparably low volatility. In other applications, such as CHP installations for district heating, heat demand follows the seasonal and daily fluctuations. In these plants, the utilization is significantly lower and reaches usually only about 4,500 h/a – 5,000 h/a. The volatility depends on the variation of the temperature, but in the long-term average, the annual utilization can be considered as very stable. We assume that the coal-fired CHP plant is used for district heating and the gas-fired CHP plant for industrial applications. Due to the forced downtime for operation and maintenance we assume that the probability distribution of the CCGT-CHP plant is truncated at a maximum utilization of 8,400 h/a. The characteristics of the utilization used for our investigation are shown in Table 6.

Table 6: Typical utilization of the different generation technologies considered

	Coal-fired plant (utilization in h/a)			**Gas-fired plant** (utilization in h/a)		
Technology	μ	σ	Probability distribution	μ	σ	Probability distribution
Condensing plant	5,000	1,000	log-normal	5,000	1,000	log-normal
CHP plant	5,000	1,000	log-normal	8,000	400	log-normal (truncated, 8,400 h max)

Source: Stylized data, derived from E.ON power plants

4.2.3 Calculation of the aggregated annual spread based on correlation coefficients

The option price model applied in our paper is based on the aggregated annual spreads for the various types of power plant technology. The aggregated annual spread AAS_i, expressed in €/kW for generation technology *i*, is the result of the convolution of the specific spread S_i in €/MWh and the power utilization U_i given by the full-load hours of the power plant:

$$AAS_i = S_i \cdot U_i \ . \qquad (3)$$

The specific spreads S_i as well as the power utilization U_i are given as probability distributions. For plants that are operated in the power-control mode, the probability variables are not independent of each other, and we need to consider the interdependency between specific spreads and plant utilization. To the best of our knowledge this is a new approach. In a first step, we do this by including the correlations. We derive the correlation by comparing the hourly production of hard-coal- and gas-fired plants with the specific spread. The production volumes are available from the transparency platform of the European Energy Exchange (EEX), and the specific spreads are based on intraday power prices. Figure 2 shows the interdependency of the specific spread for hard-coal- and gas-fired power plants. The figure illustrates that the total available hard-coal capacity in Germany (about 12,500 MW) is more than twice as high as the available capacity of gas plants (about 6,000 MW). Furthermore the correlation factor of hard-coal-fired plants is due to the typical operating mode higher than for gas-fired plants. The sharper upper bound illustrates that the total available hard-coal capacity is usually completely utilized as soon as the specific spread reaches a level above 20 €/MWh. For plants that are operated in the heat-control mode, we do not need to consider the correlation between capacity and spread, as the plants are running independently of the current specific spread.

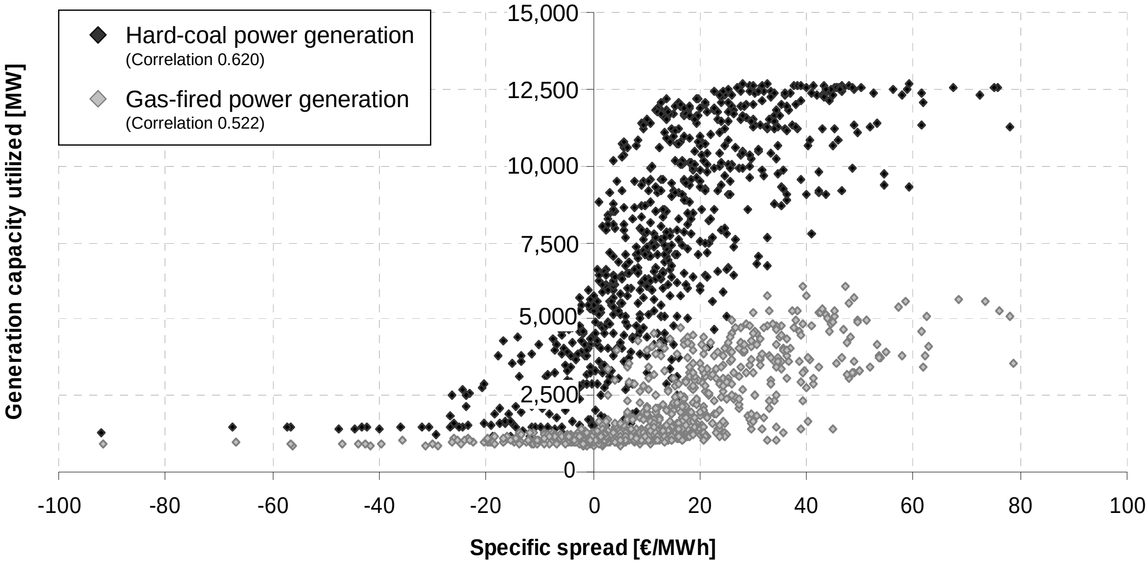


Figure 2: Interdependencies between the specific spread based on intra-day power prices and utilized generation capacity (exemplarily for December 2009)

Source: Own illustration based on data from the European Energy Exchange (EEX)

Next, we determined the probability distribution of the aggregated annual spread numerically by applying a Monte-Carlo simulation with 50,000 runs. Figure 3 reports on the probability distributions and the characteristic parameters of the aggregated annual spread for the technologies investigated. The figure shows that CHP technologies provide for both fuel types higher means of the AAS. The mean of the AAS of gas-fired CCGT-CHP amounts to 248 €/kW and is, due to the large degree of heat utilization (heat efficiency 35%), more than twice as high as the AAS of the other technologies investigated. This illustrates the economic attractiveness of high degrees of heat utilization.

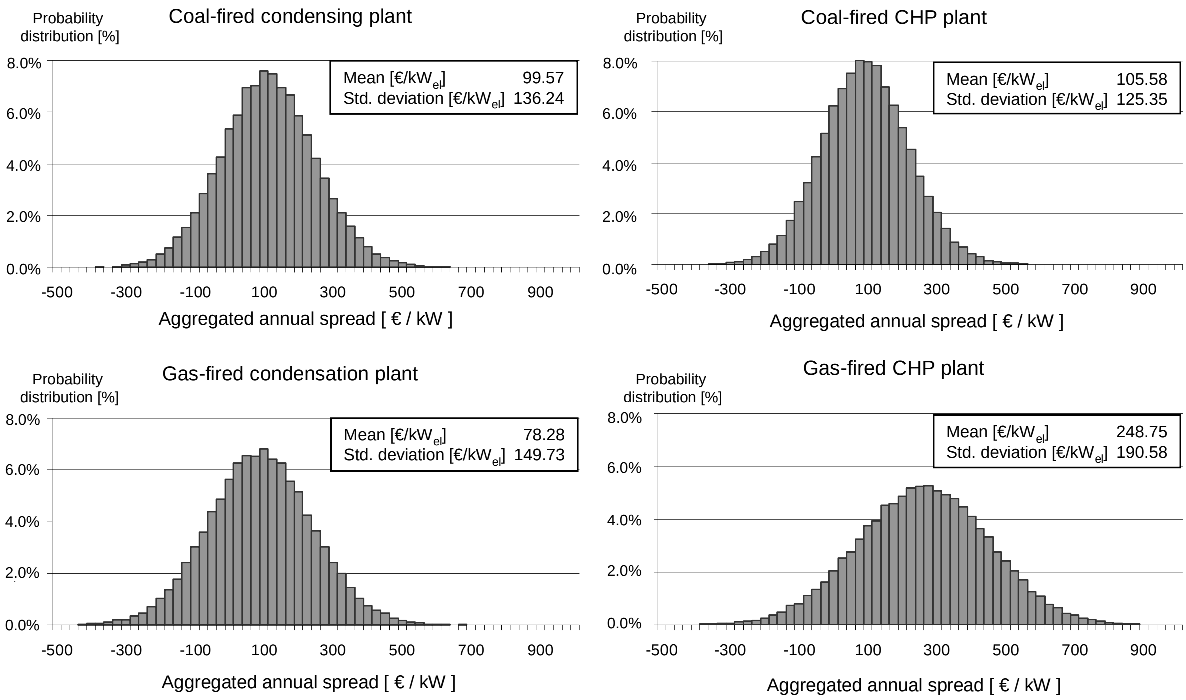


Figure 3: Probability distributions and stochastic parameter of the aggregated annual spreads based on correlation coefficients

Source: Own illustration based on the Monte-Carlo simulation of the aggregated annual spread

4.2.4 Calculation of the aggregated annual spread based on copula functions

In section 4.2.3, we used the correlation coefficients between specific spread and plant utilization to gain the probability distributions of the aggregated annual spread. This approach does not consider non-linear tail dependencies and thus may generate misleading results. Therefore, we now want to verify our results by carrying out a more sophisticated investigation of the dependence structure between specific spread and plant utilization based on copula functions. Originally, copula functions were used in the context of risk management of financial assets but in recent times this method has also been applied in the field of energy economics. Recent examples are Denault et al. (2009), who simulated the energy inflow of a generation portfolio consisting of hydro and wind generation by application of copula functions, and Valizadeh Haghi et al. (2010), who used copula functions to model the characteristics of fluctuating renewable generation in distribution networks. Before we present the results of our copula-based model, we give a brief introduction of the theory behind copula functions. A more detailed description of the copula approach can be found in Nelsen (1999).

The fundamental theory behind all copula-based analysis is known as Sklar's Theorem (Sklar, 1959). Sklar stated that if F: $\Re^d \rightarrow (0,1)$ is a joint distribution function with margins X_1, X_2, …, X_d, then there exists a copula C: $(0,1)^d \rightarrow (0,1)$ such that for all $x \in \Re^d$ and $u \in (1,0)^d$ there exists a joint distribution function

$$F(x) = C\{F_1(x_1),...,F_d(x_d)\} = C(u)\,. \qquad (4)$$

Conversely, if C:$(0,1)^d \rightarrow (0,1)$ is a copula and F_1, …, F_d are distribution functions, then there exists a joint distribution function F with margins F_1, …, F_d such that for all $x \in \Re^d$ and $u \in (1,0)^d$ there exists a copula function

$$C(u_1,...,u_n) = F\{F_1^{-1}(u_1),...,F_d^{-1}(u_d)\}\,. \qquad (5)$$

The copula function C is unique if F, F_1, …, F_d are continuous distribution functions. For our investigation, it is sufficient to consider the bivariate case, as we need to link only two variables to get the aggregated annual spread. For the bivariate case, we get the equation:

$$C(u,v) = F\{F_x^{-1}(x), F_y^{-1}(y)\}\,, \qquad (6)$$

where F is the joint cumulative distribution function (cdf) of the random vector X=(X,Y) and F_x respectively F_y are the marginal cdfs of X and Y. Bivariate copulas further need to satisfy three necessary and sufficient properties (Joe, 1995):

$$\lim_{u\rightarrow 0} C(u,v) = \lim_{v\rightarrow 0} C(u,v) = 0 \qquad (7)$$

$$\lim_{u\rightarrow 1} C(u,v) = v\ ,\ \lim_{v\rightarrow 1} C(u,v) = u \qquad (8)$$

$$C(u_1,v_1) - C(u_1,v_2) - C(u_2,v_1) + C(u_2,v_2) \geq 0 \quad \forall (u_1,v_1),(u_2,v_2) \text{ with } u_1 \leq u_2, v_1 \leq v_2 \qquad (9)$$

The choice of the copula function used to link together the marginals of two variates depends on the nature of the considered data. Each copula implies a different type of dependence between the variables. One way to identify the "right" copula function is to test several standard distribution functions like Normal-, t-student-, Clayton- or Gumbel- distribution and to select the one with the best fit (see Bastianin, 2009). Another approach is to derive copula functions based on empirical data that describe the dependence structure between the marginals. These empirical copula functions were introduced under the name "empirical dependence structure" by a series of papers by Deheuvels, starting with Deheuvels (1979). In our specific case, we apply empirical copula functions to describe the dependencies between specific spread and utilization.

To gain the empirical copula function, we need to consider the cdfs F of the random vectors X_j. The distribution function F is defined at each point x by the proportion of observations that are not greater than x. If the observed values of the vectors X_j are $x_{j1}, \ldots, x_{jn}$, and $F_1, \ldots, F_d$ are the marginal distributions, then the distribution F is mathematically given by

$$F(x_1,...,x_d) := \frac{1}{n}\sum_{i=1}^{n}\prod_{j=1}^{d} 1\{X_{ij} \le x_j\}. \tag{10}$$

The empirical copula function $\hat{C}$ of $F(x_1, \ldots, x_d)$ is then, as any copula, defined through the following identity:

$$\hat{C}(u_1,...,u_d) := F\{F_1^{-1}(u_1),...,F_d^{-1}(u_d)\} \tag{11}$$

For the bivariate case relevant to our study, we get the following identities:

$$F(x,y) \equiv \frac{1}{n}\sum_{i=1}^{n} 1(x_i \le x, y_i \le y) \tag{12}$$

$$\hat{C}(u,v) \equiv F\{F_x^{-1}(x), F_y^{-1}(y)\}. \tag{13}$$

For further details and the theoretical background of empirical copula functions, we refer to Gaenssler and Stute (1987), who have studied the empirical copula process in full generality. To model the dependence structure between specific spread and utilization, we used the commercial software ModelRisk 3.0 by Vose Software. This software is able to simulate the dependence structure between the marginals based on empirical data.

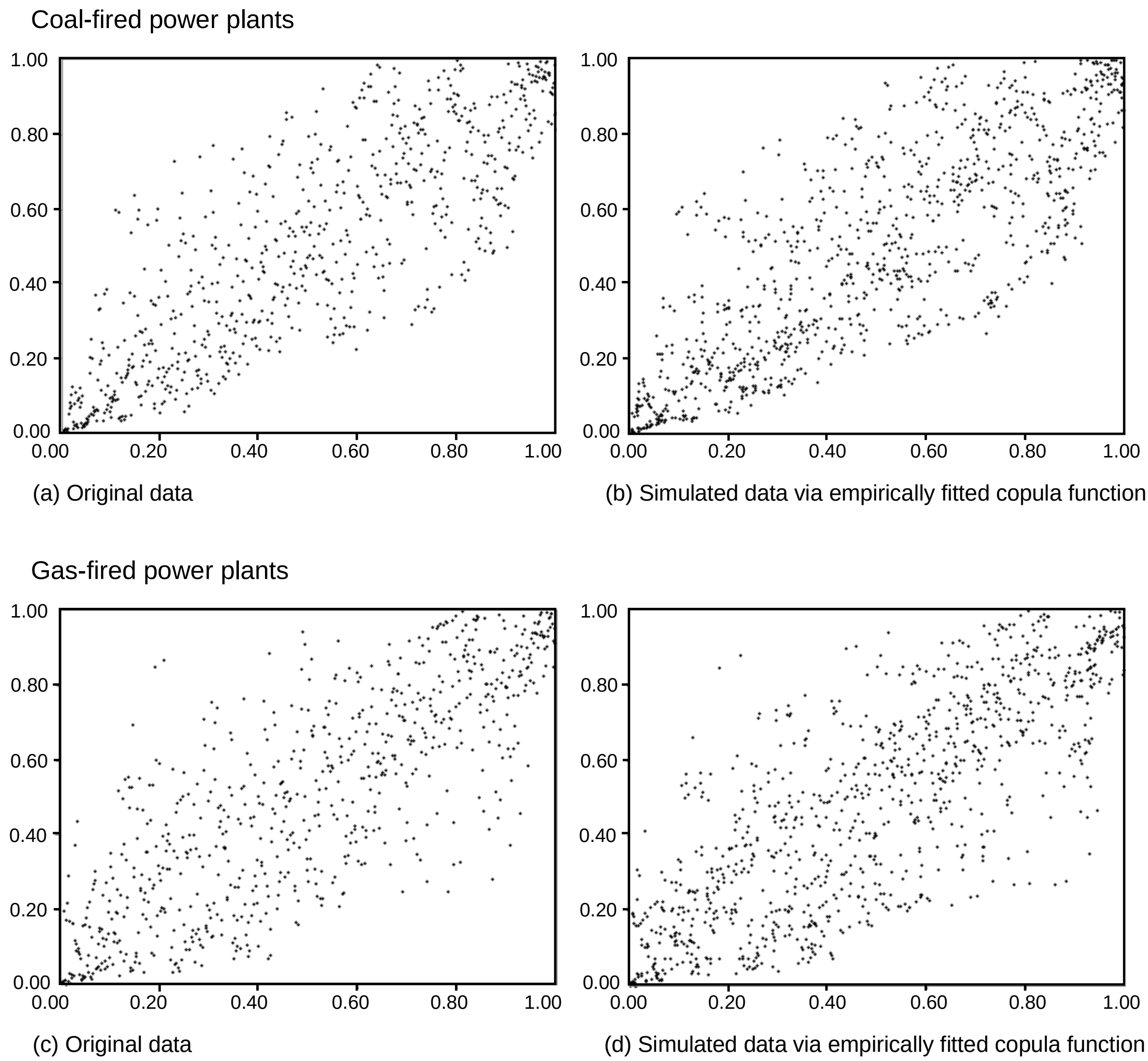


Figure 4: Simulated values of the dependence structure between specific spread and utilization for power-controlled coal-fired and gas-fired power plants

Figure 4 contains a comparison between the dependence structure of the original data and the dependence structure simulated with the applied copula functions. The visual inspection shows that the distribution of the original data is inhomogeneous within the considered interval. With the chosen copula function it is possible to reproduce this complex dependence structure between the two input variables specific spread and plant utilization quite accurately. Therefore, the copula based approach leads to more precise results in comparison to correlation coefficients that describe only a linear dependency between the variables considered.

Based on the identified empirical copula function for coal-fired and gas-fired plants, we now calculate the resulting cdfs of the aggregated annual spread by application of a Monte-Carlo-simulation with 50,000 runs. Figure 5 contains the probability distributions of the aggregated annual spread for the defined technologies and the stochastic parameter based on the calculation with empirical copula functions. The figure shows that the shape of the copula-based probability distributions of the plants that are operated in the power control mode (coal-fried condensing plant, coal-fired CHP plant and gas-fired condensing plan) is significantly different from the distributions gained via application of correlation coefficients (see Figure 3). The distributions are less regular and lose their bell-shaped form of the Gaussian distribution (except for gas-fired CHP). Additionally, the mean of the distributions is higher and the tails are fatter, which means that also the standard deviation is higher. The copula-based distribution of the gas-fired CHP plant shows the same shape as the distribution based on correlation coefficients. This is due to our assumption that there are no interferences between specific spread and utilization in the case where the plant is operated in heat control mode.

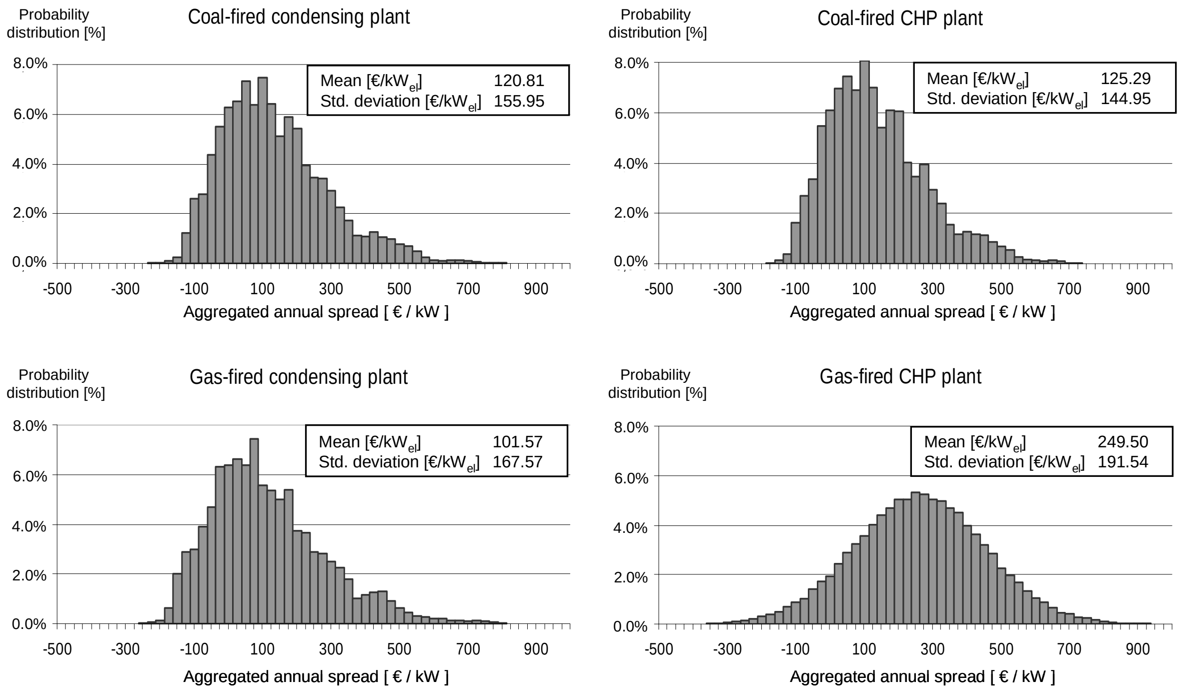


Figure 5: Probability distributions and stochastic parameters of the aggregated annual spreads based on copula functions

Source: Own illustration based on the Monte-Carlo simulation of the aggregated annual spread

5 Structure of the real options model

In this section, we apply real options theory and analyze the decision-making problem under uncertainty of investors who have the choice between investments in CHP or investments in condensing plant technology. We use a real options model that is analytically solvable and described e.g. in the seminal book by Dixit and Pindyck (1994). The decision to invest is profoundly affected by the opportunity costs of making a commitment now, and thereby giving up the option of waiting for new information. In order to apply real options theory, two preliminary conditions need to be fulfilled. First, the expenditure has to be at least partly irreversible and, second, the exercising of the investment option can be delayed, so that the investor has the opportunity to wait for new information about prices, costs, or changing market conditions before resources are committed. Both preconditions are fulfilled in the research question that we address here.

Our investigation is based on the aggregated annual spreads AAS_i, expressed in €/kW, as defined in the preceding section. To the best of our knowledge this is a novel approach, as for the first time we use an aggregated figure that includes information about commodity prices (reflected in the specific spread) and plant utilization. The investigation of Fleten and Näsäkkälä (2010), which applies the clean spark spread to derive option values of gas-fired plants, does not explicitly include the plant utilization in the real options model. We assume that the aggregated annual spread of technology *i* evolves according to the geometric Brownian motion

$$\frac{dAAS_i}{AAS_i} = \alpha_{AAS_i} dt + \sigma_{AAS_i} dz \quad , \tag{14}$$

where α_{AASi} and σ_{AASi} are constants that describe the drift and volatility of the aggregated annual spread of generation technology *i*, *dt* is an infinitesimal time increment, and *dz* is the increment of a Wiener process. The decisive parameter in our real options model is the volatility of the aggregated annual spread, therefore we ignore in the following investigation the drift and assume $\alpha_{AASi} = 0$.

In a simplified approach, we assume that the value of power plant V_i is equal to the net present value of the aggregated annual spreads AAS_i during the entire lifetime of the plant:

$$V_i = \mathrm{E}_t \left[\int_0^T AAS_i(t) e^{-\rho t} dt \right] , \quad (15)$$

where ρ is the discount rate of the investor and T is the plant lifetime. With this approach, we neglect the fixed cost components that are not part of the spread. This simplification is acceptable, as the impact of fixed cost on the volatility of the aggregated annual spread is considerably lower than the impact of volatile commodity prices. The decision to invest in a power plant can be interpreted as an optimal stopping problem, and can be solved by using a dynamic programming approach. The value of the option to invest $F(V)$ in a power plant is given by the Bellman equation

$$\rho F(V)dt = E[dF(V)] \ . \quad (16)$$

This equation implies that holding an option with the value $F(V)$ over the period dt yields an expected gain of $E[dF(V)]$. The expected gain needs to be equal to the return $\rho F(V)dt$. By applying Itô's lemma, we derive the partial differential equation

$$dF(V) = \frac{1}{2} F''(V)(dV)^2 + F'(V)(dV) \ . \quad (17)$$

Substituting (14) into (17) and noting that $E(dz) = 0$, we obtain

$$\mathrm{E}[dF(V)] = \frac{1}{2} \sigma_{AAS_i}{}^2 V^2 F''(V)dt + \alpha_{AAS_i} VF'(V)dt \ . \quad (18)$$

By substituting (18) into (16), we derive

$$\frac{1}{2} \sigma_{AAS_i}{}^2 V^2 F''(V) + \alpha_{AAS_i} VF'(V) - \rho F(V) = 0 \ . \quad (19)$$

In addition, V_i must satisfy the following boundary conditions:

$$F(0) = 0 \quad (20)$$

$$F(V^*) = V^* - I \qquad (21)$$

$$F'(V^*) = 1 \ . \qquad (22)$$

Condition (20) arises from the observation that if the value goes to zero, it will remain zero (this is an implication of the stochastic process described in (14)). V^* represents the critical plant value at which it is optimal to invest and (21) is the value-matching condition that defines the net payoff (V^* - I) of the investor. Eq. (22) is the so-called smooth-pasting condition that guarantees that the gradient of the first deviation is equal at the exertion point. To get the value $F(V)$ of the investment option, we need to solve (19) subject to the boundary conditions (20)-(22). Eq. (19) represents a second-order homogeneous differential equation that is linear in the dependent variable F and its derivatives. The general solution can be expressed as a linear combination of two independent solutions and written as

$$F(V) = A_1 V^{\beta_1} + A_2 V^{\beta_2} \ , \qquad (23)$$

where A_1 and A_2 are constants and β_1 and β_2 are the roots of the quadratic function

$$\frac{1}{2}\sigma_{AAS_i}{}^2 \beta(\beta - 1) + (\rho - \alpha_{AAS_i})\beta - \rho = 0 \ . \qquad (24)$$

Note that β_1 and β_2 depend on the parameters α_{AASi} and σ_{AASi} of the differential equation and the discount rate of the investor ρ in the following way:

$$\beta_i = \frac{1}{2} - \frac{\alpha_{AAS_i}}{\sigma_{AAS_i}{}^2} \pm \sqrt{\left[\frac{\alpha_{AAS_i}}{\sigma_{AAS_i}{}^2} - \frac{1}{2}\right]^2 + \frac{2\rho}{\sigma_{AAS_i}{}^2}} > 1 \ . \qquad i = \{1,2\} \qquad (25)$$

In our case, boundary condition (20) implies that A_2=0, so the solution takes the form

$$F(V) = AV^{\beta_1} \ . \qquad (26)$$

The remaining boundary conditions can be used to define the two remaining unknowns: the critical value V^* at which it is optimal to invest, and the constant A:

$$V^* = \frac{\beta_1}{\beta_1 - 1} I \quad , \tag{27}$$

$$A = \frac{V^* - I}{(V^*)^{\beta_1}} = \frac{(\beta_1 - 1)^{\beta_1 - 1}}{(\beta_1)^{\beta_1} \cdot I^{\beta_1 - 1}} \quad . \tag{28}$$

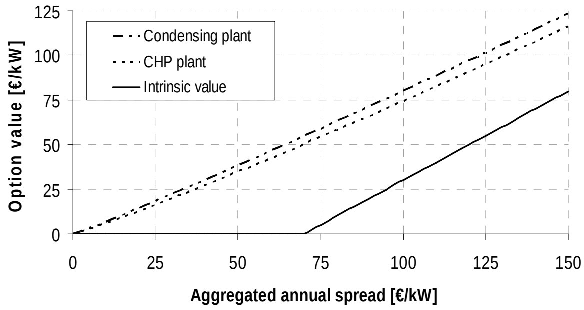
Based on the given equations it is possible to analytically determine option values of the above-described generation technologies.

6 Discussion and interpretation of the results

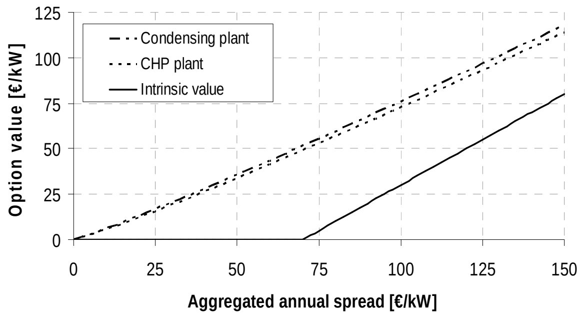
In this section, we present the results gained with our model and interpret them on two levels. First, we describe the difference in the option value between condensing and CHP technology. Then, we analyze how the option value of coal-fired CHP plants is influenced by the degree of CHP generation. For both cases, we show the differences between the calculation based on correlation coefficients and the calculation based on copula functions.

6.1 Difference between condensing plants and CHP plants

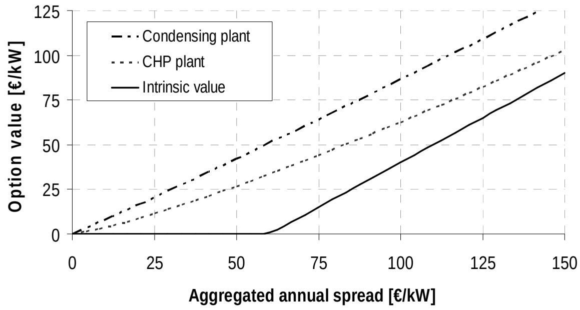
In our model, we investigated four different investment options: coal-fired condensing plant, coal-fired CHP plant, gas-fired CCGT condensing plant, and gas-fired CCGT-CHP plant. The option values of investment with the same fuel type differ significantly between condensing plants and CHP plants. Figure 6 shows the option value as a function of the aggregated annual spread.



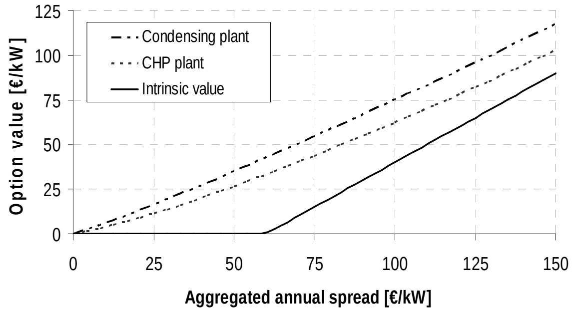
(a) Coal-fired plants, correlation coefficient



(b) Coal-fired plants, copula function



(c) Gas-fired plants, correlation coefficient



(d) Gas-fired plants, copula function

Figure 6: Option value of investment decisions for CHP and condensing plants as a function of the aggregated annual spread

The option values of condensing plants, irrespective of whether they are coal-fired or gas-fired, are higher than the option value of the respective CHP plant. For coal-fired plants the difference between condensing and CHP technology at the strike price of 70 €/kW amounts to 7.7 €/kW in the correlation based case (4.2 €/kW in the copula based case). For gas-fired CCGT plants the difference between condensing and CHP technology at the strike price of 66 €/kW amounts to 19.2 €/kW in correlation based case (13.5 €/kW in the copula based case). The differences in the strike price result from the energy economical assumptions for the various plant types as described in section 4. For investors, this is an indication that the uncertainty and risks involved with investments in condensing plants are higher compared to CHP generation. According to the results of our model it is, therefore, more likely that investment decisions in condensing plants will be postponed or even cancelled. On the other hand, the investment decision for CHP plants might be executed earlier, as the option value (i. e. the value of waiting) is lower. These findings can motivate utilities to invest in CHP generation instead of condensing plants, especially in periods with a high degree of uncertainty.

For coal-fired plants, the difference in the option value between condensing technology and CHP technology is smaller than for gas-fired CCGT plants. The major reason for this is that the share of CHP power generation in the coal-fired plant, due to the specific characteristics and the defined operation mode, is lower than in the gas-fired CCGT plant. Therefore, risk-averse utilities that aim to invest promptly in new generation technologies will prefer CHP plants with a high share of CHP generation. For both fuel types, we calculated the option values based on the distributions gained by the application of correlation coefficients and the distributions gained via copula functions. The results show basically the same tendency, but the application of copula functions leads to less significant differences between condensing and CHP plants. This effect is more distinctive for gas-fired power plants than for coal-fired plants.

6.2 Influence of CHP generation on investment decisions in coal plants

Large coal-fired CHP plants, such as the generic plant defined in this paper, are often operated in the power control mode and produce heat as a by-product of the generated power. In many cases, there exists no heat sink close to the plant site that is large enough to allow for a complete utilization of the waste heat. The transport of heat to remote sites with an additional demand is economically less attractive due to the high losses of heat transportation over long distances. In many applications, the degree of CHP generation in a coal-fired power plant is therefore limited by the local heat demand in the area where the plant is located. The fuel utilization of a modern coal-fired CHP plant depends on the degree of CHP generation and varies in a range between 45% in the case of pure power generation, and up to 85% in a plant with the maximum possible degree of heat utilization. Typical sites for efficient coal-fired CHP plants with a high degree of CHP generation (and consequently high fuel utilization) are close to big factories, industrial parks with high heat demand, or near to big cities using the produced heat for district heating. With our model, we analyze the influence of the degree of CHP generation on the option value of the investment and thus on the rational decision-making of an investor. In order to quantify this effect, we vary the degree of fuel utilization by starting with a pure condensing plant until we reach a value of 85%, and calculate with our spread-based model the option value of the investment options concerned. In this context, we need to consider how the volatility of the specific spread S is affected by the total fuel utilization ζ of the coal-fired CHP plant, which is illustrated in Figure 7. The figure shows that spread-volatility decreases if fuel utilization (or the share of CHP generation respectively) increases. The reason behind this characteristic is that with an increase in CHP generation the share of stable revenue components, such as CHP promotion, also increases, which reduces the volatility of the spread and, as a consequence, also the risk exposure of the investor.

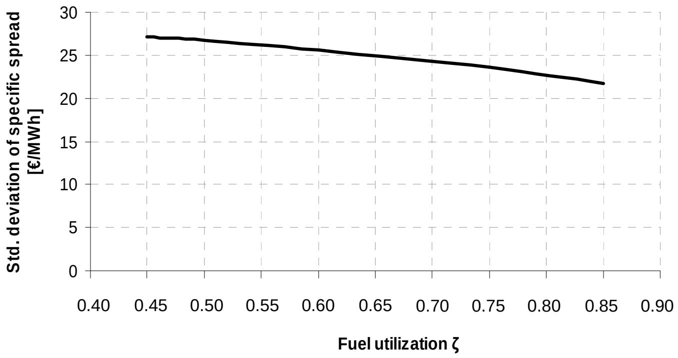
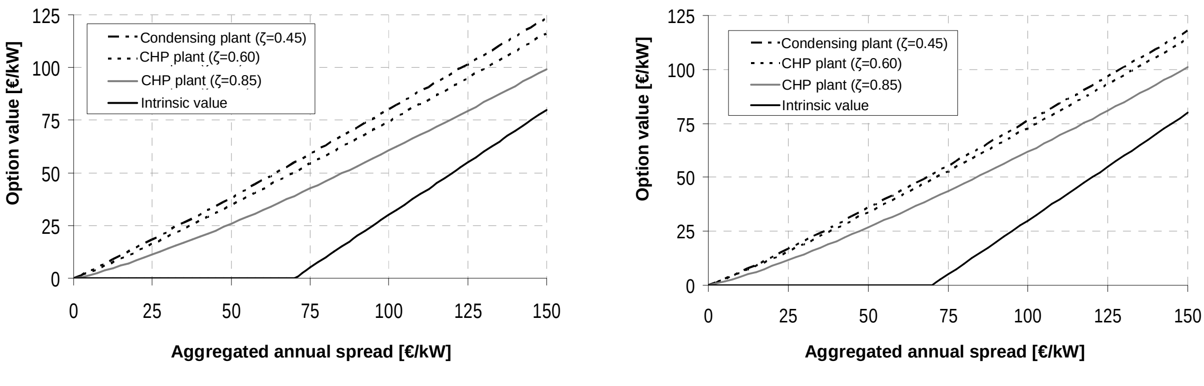


Figure 7: Relation between standard deviation of the specific spread and fuel utilization for a coal-fired CHP plant

In a next step, we derive with our model the option values of coal-fired plants in dependence of the fuel utilization that is, as mentioned above, strongly correlated with the degree of CHP generation. Figure 8 depicts the option values as a function of the aggregated annual spread. The figure again illustrates the differences between the calculation based on correlation coefficients and the calculation based on copula functions.



(a) Calculation based on correlation coefficient

(b) Calculation based on copula function

Figure 8: Option value of coal-fired plants in dependence of the fuel utilization as a function of the specific aggregated annual spread

The results show that the uncertainty involved with new investments in coal-fired plants is reduced if the heat of the plant is also utilized. The higher the share of CHP generation of a coal-fired power plant, the lower the uncertainty for the investor is. An increase in the degree of fuel utilization from 60% to 85%, which is directly correlated to the share of CHP generation, reduces the option value at the strike price from 50.0 €/kW to 41.7 €/kW in the case based on correlation coefficients (from 53.3 €/kW to 43.3 €/kW in the case based on copula functions, respectively). In the practical application, this means that it is beneficial if the sites of large coal-fired plants are close to sizable heat sinks that can utilize as much as possible of the heat produced. In the case where the dependence structure is modeled via copula functions, the observed effect is again less pronounced than by application of correlation coefficients.

7 Conclusions

In this paper we have applied real options theory on investment decisions of new fossil-fired power plants and have derived some conclusions about the uncertainty related with different investment options. Our model is calibrated for the German power market. For other countries the results may deviate from our findings as commodity prices levels and CHP promotion schemes are different (Westner and Madlener, 2009). Our investigation puts a focus on CHP generation in comparison to condensing plants. Due to their specific characteristics, such as additional revenues from heat sales, CHP promotion schemes, specific operational features, and a beneficial allocation of CO_2 allowances, CHP plants have considerably different risk profiles compared to condensing plants. These specifics can affect the decision-making process of an investor. The real options model applied is based on aggregated annual spreads used to calculate the value of various investment options. We take the aggregated annual spread as an assessment criterion since it contains the relevant volatile input parameters that have an impact on the valuation of investment decisions. We determined the aggregated annual spread independently in two different ways, by the application of correlation coefficients and copula functions, and show the deviation between these two approaches. The copula-based approach is able to better reproduce the complex dependence structure between the input variables and, therefore, leads to more precise results in comparison to the correlation-based investigation that considers only a linear dependency. The results gained by the real options model provide some insights for investors who intend to invest in new power generation capacity in Germany. We show that the option values of fossil-fired power plants with CHP generation are lower than those of the same technology without heat utilization. As a consequence, the value of waiting of investment decisions in CHP plants is lower, and investing utilities can decide with less uncertainty whether they want to make a commitment for a new plant. Another finding of our research is that the option value depends on the operation mode of the plant and on fuel-type-specific characteristics. An expansion of the degree of CHP generation at coal-fired plants reduces the option value and therefore reduces uncertainty for the investor. Our findings could have an impact on the evaluation of the siting for new large-scale fossil power plants. As the possible degree of CHP generation depends significantly on the local heat demand in the surrounding of the plant site, the size of the heat sink available could therefore gain more relevance in the future in comparison to other selection criteria for plant sites. The results obtained are only conditionally transferable to other countries, as some of the risk-reducing effects of CHP generation depend on the country-specific frameworks, which can differ significantly.

In addition to the specific characteristics of CHP generation, which are considered in our investigation, there are two further aspects that could also contribute towards decreasing the risk exposure of CHP generation. These are privileged feed-in conditions and a better public acceptance. Grid operators in Germany are legally obliged to purchase the power produced in CHP plants prior to other kinds of conventional generation (preferential dispatch). This is an advantage especially in areas where conventional power plants are often re-dispatched due to limitations in the transmission grid. Especially if the fluctuating wind generation in Northern Germany increases further, the privileged feed-in conditions of CHP generation could become a significant benefit. Additionally, CHP generation faces in comparison to condensing plants less resistance from the public. High efficiency and less environmental impacts (e.g. abandonment of cooling towers) increase public acceptance and reduce the risks of legal disputes or building freezes for the investing utilities. Our research puts its major focus on the energy economic aspects and does not consider the advantages through the power purchase obligation or the better public acceptance of CHP generation, which leaves room for further investigation.

References

Bastianin, A., 2009. Modelling asymmetric dependence using copula functions: an application to value-at-risk in the energy sector. Working Paper 2009.24, Fondazione Eni Enrico Mattei.

Black, F., Scholes, M., 1973. The pricing of options and corporate liabilities. Journal of Political Economy, I 81, 637–659.

Blok, K., Turkenburg, W., 1994. CO_2 emission reduction by means of industrial CHP in the Netherlands. Energy Conversion and Management, 35 (4), 317–340.

Blyth, W., Bradley, R., Bunn, D., Clarke, C., Wilson, T., Yang, M., 2007. Investment risks under uncertain climate change policy. Energy Policy, 35 (11), 5766–5773.

BMU, 2006. Nationaler Allokationsplan 2008-2012 für die Bundesrepublik Deutschland, Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU), Berlin, June.

Copeland, T., Antikarov, V., 2001. Real Options: A Practitioner’s Guide. WW Norton & Co, New York City.

Deheuvels, P., 1979. La fonction de dépendance empirique et ses propriétés. Un test nonparamétrique d’indépendance. Bulletin de la Classe des Sciences, Académie Royale de Belgique, 65 (6), 274–292.

Denault, M., Dupuis, D., Couture-Cardinal, S., 2009. Complementarity of hydro and wind power: Improving the risk profile of energy inflows. Energy Policy, 37 (12), 5376-5384.

Dittmann, A., Sander, T., Menzler, G., 2009. Die ökologische Bewertung von Wärme und Elektroenergie ein Instrument zur Erhöhung der Akzeptanz der Kraft-Wärme-Kopplung. VIK Mitteilungen – Sonderdruck, Juni 2009.

Dixit, A.K., Pindyck, R.S., 1994. Investment under Uncertainty. Princeton University Press, Princeton, NJ.

EEG, 2008. Gesetz für den Vorrang Erneuerbarer Energien vom 25.10.2008 (BGBl. I S. 2074), Berlin.

EU, 2009. Directive 2009/29/EC amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community. Commission of the European Communities, Brussels, April 23, 2009.

Fleten, S.E., Näsäkkälä, E., 2010. Gas-fired power plants: investment timing, operating flexibility and CO_2 capture. Energy Economics 32 (4), 805–816.

Gaenssler, P., Stute, W., 1987. Seminar on Empirical Processes. DMV Seminar 9, Birkhäuser Verlag, Basel.

Hlouskova, J., Kossmeier, S., Obersteiner, M., Schnabl, A., 2005. Real options and the value of generation capacity in the German electricity market. Review of Financial Economics, 14 (3–4), 297–310.

International Energy Agency (IEA), 2007. Modelling investment risks and uncertainties with real options approach. IEA Working Paper Series LTO/2007/WP01, February.

International Energy Agency (IEA), 2008a. World Energy Outlook 2009. OECD/IEA, Paris.

International Energy Agency (IEA), 2008b. Combined Heat and Power. OECD/IEA, Paris.

Ishii, J., Yan, J., 2004. Investment under regulatory uncertainty: US electricity generation investment since 1996. Center for the Study of Energy Markets, University of California Energy Institute, Berkeley, CSEM Working Paper 127, March 2004.

Joe, H., 1997. Multivariate Models and Dependence Concepts, Chapman & Hall, London.

Kumbaroğlu, G., Madlener, R., Demirel, M., 2008. A real options evaluation model for the diffusion prospects of new renewable power generation technologies. Energy Economics, 30 (4), 1882–1908.

KWK-Gesetz, 2008. Gesetz zur Förderung der Kraft-Wärme-Kopplung vom 25. Oktober 2008 (BGBl. I S. 2101), Berlin.

McDonald, R., Siegel, D., 1986. The value of waiting to invest. Quarterly Journal of Economics, 101 (4), 707–723.

Merton, R., 1973. The theory of rational option pricing. Journal of Economic Management Science, 4 (1), 141–183.

Murto, P., Nese, G., 2003. Input price risk and optimal timing of energy investment: choice between fossil and biofuels. Working Paper No. 25/02, Institute for Research in Economics and Business Administration, Bergen, Norway.

Nelsen, R., 1999. An Introduction to Copulas. Springer Verlag, New York.

Näsäkkälä, E., Fleten, S.E., 2005. Flexibility and technology choice in gas-fired power plant investments. Review of Financial Economics, 14 (3-4), 371–393.

Pahle, M., 2010. Germany’s dash for coal: Exploring drivers and factors. Energy Policy, 38 (7), 3431–3442.

Pindyck, R., 1988. Irreversible investment, capacity choice, and the value of the firm. American Economic Review 79 (5), 969–985.

Pindyck, R., 1991. Irreversibility, uncertainty and investment. Journal of Economic Literature, 29 (3), 1110–1152.

Pindyck, R., 1993. Investments of uncertain cost. Journal of Financial Economics, 34 (1), 53–76.

Roques, F.A., Savva, N.S., 2006. Price cap regulation and investment incentives under demand uncertainty. Working Paper CWPE 0636 and EPRG 0616, Electricity Policy Research Group, University of Cambridge, Cambridge, May.

Rothwell, T., 2006. A real options approach to evaluating new nuclear power plants. The Energy Journal, 27 (1), 37–54.

Valizadeh Haghi, H., Tavakoli Bina, M., Golkar, M.A., Moghaddas-Tafreshi, S.M., 2010. Using copulas for analysis of large datasets in renewable distributed generation: PV and wind power integration in Iran, Renewable Energy, 35 (9), 1991–2000.

Siddiqui, A.S., Maribu, K., 2009. Investment and upgrade in distributed generation under uncertainty. Energy Economics, 31 (1), 25–31.

Sklar, A., 1959. Fonctions de répartition à n dimensions et leurs marges. Publications de l'Institut de Statistique de l'Université de Paris, Volume 8, 229–231.

Sundberg, G., Sjödin, J., 2003. Project financing consequences on cogeneration: industrial plant and municipal utility co-operation in Sweden. Energy Policy, 31 (6), 491–503.

Trigeorgis, L., 1996. Real Options - Managerial Flexibility and Strategy in Resource Allocation. MIT Press, Cambridge, MA.

Westner, G., Madlener, R., 2009. The benefit of regional diversification of CHP investments in Europe: A Mean-Variance Portfolio analysis. FCN Working Paper No. 5/2009, Institute for Future Energy Consumer Needs and Behavior (FCN), RWTH Aachen University, November.

Wickart, M., Madlener, R., 2007. Optimal technology choice and investment timing: A stochastic model of industrial cogeneration vs. heat-only production. Energy Economics, 29 (4), 934–952.

Yang, M., Blyth, W., Bradley, R., Bunn, D., Clarke, C., Wilson, T., 2008. Evaluating the power investment options with uncertainty in climate policy. Energy Economics, 30 (4), 1933–1950.

Appendix: Results from the Monte Carlo Simulation

Table A.1: Statistics of the aggregated annual spread

(a) Based on correlation coefficients

	Coal-fired plants (Aggregated annual spread in €/kW$_{el}$)		**Gas-fired plants** (Aggregated annual spread in €/kW$_{el}$)	
Statistics	Condensing	CHP	Condensing	CHP
Runs	50,000	50,000	50,000	50,000
Mean	**99.56625**	**105.58353**	**78.28193**	**248.74537**
Mode	---	---	---	---
Standard deviation	**136.23780**	**125.34613**	**149.72624**	**190.57906**
Variance	18,560.738	15,711.652	22,417.946	36,320.378
Skewness	0.0392	0.0385	0.0256	0.0019
Kurtosis	3.11	3.10	3.11	3.02
Coeff. of variability	1.368	1.187	1.913	0.766
Minimum	-511.75196	-415.70166	-571.99855	-583.80831
Maximum	729.69097	707.57227	777.39406	1,151.51227
Range width	1,241.44293	1,123.27393	1,349.39261	1,735.32058

(b) Based on copula functions

	Coal-fired plants (Aggregated annual spread in €/kW$_{el}$)		**Gas-fired plants** (Aggregated annual spread in €/kW$_{el}$)	
Statistics	Condensing	CHP	Condensing	CHP
Runs	50,000	50,000	50,000	50,000
Mean	**120.81491**	**125.29147**	**101.57156**	**249.50495**
Mode	---	---	---	---
Standard deviation	**155.95226**	**144.95471**	**167.57349**	**191.54212**
Variance	24,321.107	21,011.865	28,080.875	36,688.383
Skewness	0.8209	0.7981	0.8186	0.0204
Kurtosis	3.69	3.61	3.74	3,01
Coeff. of variability	1.291	1.157	1.650	0.767
Minimum	-271.296	-225.53456	-350.93104	-528.28511
Maximum	849.55379	866.54618	901.46428	1138.02481
Range width	1,120.84979	1,092.08074	1,252.39532	1,666.30992

E.ON Energy Research Center

fcn Institute for Future Energy Consumer Needs and Behavior

RWTH AACHEN UNIVERSITY

List of FCN Working Papers

2010

Westner G., Madlener R. (2010). Investment in New Power Generation under Uncertainty: Benefits of CHP vs Condensing Plants in a Copula-Based Analysis, FCN Working Paper No. 12/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, September.

Lang J., Madlener R. (2010). Relevance of Risk Capital and Margining for the Valuation of Power Plants: Cash Requirements for Credit Risk Mitigation, FCN Working Paper No. 1/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, February.

Michelsen C., Madlener R. (2010). Integrated Theoretical Framework for a Homeowner's Decision in Favor of an Innovative Residential Heating System, FCN Working Paper No. 2/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, February.

Harmsen - van Hout M.J.W., Herings P.J.-J., Dellaert B.G.C. (2010). The Structure of Online Consumer Communication Networks, FCN Working Paper No. 3/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, March.

Madlener R., Neustadt I. (2010). Renewable Energy Policy in the Presence of Innovation: Does Government Pre-Commitment Matter?, FCN Working Paper No. 4/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, April (revised June 2010).

Harmsen-van Hout M.J.W., Dellaert B.G.C., Herings, P.J.-J. (2010). Behavioral Effects in Individual Decisions of Network Formation: Complexity Reduces Payoff Orientation and Social Preferences, FCN Working Paper No. 5/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, May.

Lohwasser R., Madlener R. (2010). Relating R&D and Investment Policies to CCS Market Diffusion Through Two-Factor Learning, FCN Working Paper No. 6/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, June.

Rohlfs W., Madlener R. (2010). Valuation of CCS-Ready Coal-Fired Power Plants: A Multi-Dimensional Real Options Approach, FCN Working Paper No. 7/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, July.

Rohlfs W., Madlener R. (2010). Cost Effectiveness of Carbon Capture-Ready Coal Power Plants with Delayed Retrofit, FCN Working Paper No. 8/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, August.

Gampert M., Madlener R. (2010). Pan-European Management of Electricity Portfolios: Risks and Opportunities of Contract Bundling, FCN Working Paper No. 9/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, August.

Glensk B., Madlener R. (2010). Fuzzy Portfolio Optimization for Power Generation Assets, FCN Working Paper No. 10/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, August.

Lang J., Madlener R. (2010). Credit Risk Mitigation Applying Margining: Impact on Power Plant Portfolio Selection, FCN Working Paper No. 11/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, September.

Lang J., Madlener R. (2010). Investment in New Power Generation Under Uncertainty: Benefits of CHP vs. Condensing Plants in a Copula-Based Analysis, FCN Working Paper No. 12/2010, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, September.

2009

Madlener R., Mathar T. (2009). Development Trends and Economics of Concentrating Solar Power Generation Technologies: A Comparative Analysis, FCN Working Paper No. 1/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

Madlener R., Latz J. (2009). Centralized and Integrated Decentralized Compressed Air Energy Storage for Enhanced Grid Integration of Wind Power, FCN Working Paper No. 2/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November (revised September 2010).

Kraemer C., Madlener R. (2009). Using Fuzzy Real Options Valuation for Assessing Investments in NGCC and CCS Energy Conversion Technology, FCN Working Paper No. 3/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

Westner G., Madlener R. (2009). Development of Cogeneration in Germany: A Dynamic Portfolio Analysis Based on the New Regulatory Framework, FCN Working Paper No. 4/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November (revised March 2010).

Westner G., Madlener R. (2009). The Benefit of Regional Diversification of Cogeneration Investments in Europe: A Mean-Variance Portfolio Analysis, FCN Working Paper No. 5/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November (revised March 2010).

Lohwasser R., Madlener R. (2009). Simulation of the European Electricity Market and CCS Development with the HECTOR Model, FCN Working Paper No. 6/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

Lohwasser R., Madlener R. (2009). Impact of CCS on the Economics of Coal-Fired Power Plants – Why Investment Costs Do and Efficiency Doesn't Matter, FCN Working Paper No. 7/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

Holtermann T., Madlener R. (2009). Assessment of the Technological Development and Economic Potential of Photobioreactors, FCN Working Paper No. 8/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

Ghosh G., Carriazo F. (2009). A Comparison of Three Methods of Estimation in the Context of Spatial Modeling, FCN Working Paper No. 9/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

Ghosh G., Shortle J. (2009). Water Quality Trading when Nonpoint Pollution Loads are Stochastic, FCN Working Paper No. 10/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

Ghosh G., Ribaudo M., Shortle J. (2009). Do Baseline Requirements hinder Trades in Water Quality Trading Programs?, FCN Working Paper No. 11/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

Madlener R., Glensk B., Raymond P. (2009). Investigation of E.ON's Power Generation Assets by Using Mean-Variance Portfolio Analysis, FCN Working Paper No. 12/2009, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, November.

2008

Madlener R., Gao W., Neustadt I., Zweifel P. (2008). Promoting Renewable Electricity Generation in Imperfect Markets: Price vs. Quantity Policies, FCN Working Paper No. 1/2008, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, July (revised May 2009).

Madlener R., Wenk C. (2008). Efficient Investment Portfolios for the Swiss Electricity Supply Sector, FCN Working Paper No. 2/2008, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, August.

Omann I., Kowalski K., Bohunovsky L., Madlener R., Stagl S. (2008). The Influence of Social Preferences on Multi-Criteria Evaluation of Energy Scenarios, FCN Working Paper No. 3/2008, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, August.

Bernstein R., Madlener R. (2008). The Impact of Disaggregated ICT Capital on Electricity Intensity of Production: Econometric Analysis of Major European Industries, FCN Working Paper No. 4/2008, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, September.

Erber G., Madlener R. (2008). Impact of ICT and Human Skills on the European Financial Intermediation Sector, FCN Working Paper No. 5/2008, Institute for Future Energy Consumer Needs and Behavior, RWTH Aachen University, September.

FCN Working Papers are free of charge. They can mostly be downloaded in pdf format from the FCN / E.ON ERC Website (www.eonerc.rwth-aachen.de/fcn) and the SSRN Website (www.ssrn.com), respectively. Alternatively, they may also be ordered as hardcopies from Ms Sabine Schill (Phone: +49 (0) 241-80 49820, E-mail: post_fcn@eonerc.rwth-aachen.de), RWTH Aachen University, Institute for Future Energy Consumer Needs and Behavior (FCN), Chair of Energy Economics and Management (Prof. Dr. Reinhard Madlener), Mathieustrasse 6, 52074 Aachen, Germany.