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PhD Thesis

Regulatory impacts in relation to a renewable fuel CHP technology: A financial and socioeconomic analysis

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Regulatory impacts in relation to a renewable fuel CHP technology: A financial and socioeconomic analysis

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Acknowledgements

"No [person] is an island"[1]. I could not agree more. That no work is truly accomplished alone, that we stand on the shoulders of giants, interlinked with both past and present generations, all of this I take as truth. But John Donne, who originally coined the phrase "no man is an island", has clearly not spent much time on islands. There is nowhere like an island to make you aware of how much you rely on your environment, how vital social interaction in terms of trade of physical goods and of ideas and energy really is. You may be cognizant of these values when you live in cities on the mainland, but without the threat of potential isolation caused by rough seas, blizzards and network failures lived with on a day-to-day basis, you end up taking them for granted.

I have knowingly and unknowingly often taken support given to me for granted. I hope that by attempting to acknowledge all those who have made a direct contribution to the completion of this thesis, I have in some small way compensated for this oversight. Most likely, I have managed to forget important contributions, for which I sincerely apologise.

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Thank you to Henrik Scriver from the PhD school for taking a personal interest in my PhD application and for being genuinely pleased on my behalf when the original funding came through. That phone call was the unequivocal highlight of my summer in 2010.

[1] John Donne, Meditations 17 - Modern Version, Devotions Upon Emergent Occasions, 1624. Word in square brackets changed from "man" to "person" by author.

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I have reserved three acknowledgements for last. Much like a good whisky can be improved by enveloping it in different barrels, subtly altering the flavour without overpowering it, so too I have benefited immeasurably from the contributions of three unique individuals.

My academic advisor, Professor Jan Børsen Bentzen. From providing original guidance into the intricacies of cost benefit analysis, to supervising me in my MSc thesis and for sticking with me while convincing Stirling.DK to hire me, the first PhD application process, the second PhD application process, my leave of absence, the university merger, the company bankruptcy, my doubts and insecurities and inevitable distractions and finally to this completed dissertation.

I have read and heard of many supervisor-student relationships, but none come close in terms of the unwavering, dedicated and indisputable support that you have shown me. You have never expressed a second of doubt in terms of the quality and content of my research. You have always taken the time to listen to me, not only in terms of my research progress but also in terms of getting to know me personally. You have gently admonished me when flights of fancy have taken me far off-track, frequently helped me discipline myself in terms of time management and always, always offered constructive advice and insight into the workings of academia.

My mentor, Mr. Svend Erik Christesen. On my very first day at Stirling.DK, you pulled me into a car and took me on a site visit so I would be prepared on the following Saturday to speak to the uninitiated on the benefits of an updraft gasification, wood-chip powered, externally combusted Stirling engine system. It was a memorable beginning to the most rewarding mentoring relationship I have ever had. You have always been a ready listener, offering constructive advice and providing as many opportunities for growth as I could bear. Your insights and unflinching support of my dreams and ambitions have meant more to me than I could ever successfully articulate, much less repay. Thank you for all of your time and energy.

My grandmother, Mrs. Inger Marie Groth Pedersen. Tak.

Declaration

I hereby avow that the content of this dissertation consists of fully original work resulting from my own research efforts unless otherwise indicated. It includes articles co-authored with Mr. Gerald Marinitsch, Mr. Stephen Newman, Professor Bert Scholtens and Professor Jan Bentzen. All work quoted in this dissertation which originates from other people's work has been clearly and specifically acknowledged and referenced. All sources can be found in the respective references for each chapter.

I further submit that this dissertation is not and has not been submitted to any other university for review.

Tanja Groth
31.01.2014

This dissertation was edited in May 2014.

Declaration of Joint Authorship

Three articles in this thesis are the result of a joint effort. The contribution of each respective author is detailed in the following paragraphs.

The article "*Chapter II: Applications of a Stirling engine based woodchip fired trigeneration system in UK supermarkets*", section 3 of this thesis, is joint work with Mr. Gerald Marinitsch, previously Head of Research and Development at Stirling.DK Ltd Ltd and Mr. Stephen Newman, Technical Director at MITIE. The work was presented at the European Biomass Conference and Exhibition June 2012 held in Milan, Italy. The idea for the paper was developed jointly, with technical data written and provided by Mr. Marinitsch and Mr. Newman. Ms. Groth was lead author for the paper and responsible for the remainder of the content, including final editing and presentation at the conference.

Confirmation of co-authorship signed by Mr. Marinitsch on November 18, 2013.

Confirmation of co-authorship from Mr. Newman has been replaced by a note detailing why confirmation was not given, signed by Ms. Groth and Professor Bentzen on January 13, 2014.

The article "*Chapter III: Assessing the EU renewable electricity subsidy harmonization ambition: A comparison of cost-benefit analysis approaches to biomass and natural gas CHP projects in Denmark and the Netherlands*", chapter 4 of this thesis, is joint work with Professor Bert Scholtens of the University of Groningen. The idea for the paper was proposed by Ms. Groth and then developed jointly. Professor Scholtens led the development of the framework while Ms. Groth was responsible for the data and calculations. Revisions of the paper were realized jointly by alternating the draft between the two authors.

Confirmation of co-authorship signed by Professor Scholtens on January 14, 2014.

The article "*Chapter VI: Prices of agricultural commodities, biofuels and fossil fuels in long-run relationships – a comparative study for the USA and Europe*", chapter 7 of this thesis, is joint work with Professor Jan Bentzen of Aarhus University. The idea for the paper was proposed by Professor Bentzen and then developed jointly. Ms. Groth provided the necessary regulatory framework for the paper while Professor Bentzen was responsible for the data and calculations. Each contributed drafts of their respective sections and revisions of the paper were realized jointly by alternating the draft between the two authors.

Confirmation of co-authorship signed by Professor Bentzen on January 14, 2014.

Summary

This PhD dissertation was motivated by two questions. The first question was quite simply what, if any, relationship monetary support for renewable energy deployment has with the externalities of a given technology, and does this relationship vary across national borders? In other words, if an investment has a net increase in welfare, is the magnitude of that benefit reflected in the support given – and are there differences from country to country? Are support schemes a way of internalizing positive market externalities the same way taxes have been used to internalize negative ones?

The second question is a natural extension of the first. Where firms are believed to be inherently profit-maximising, are governments correspondingly motivated by maximising net gains to welfare? Given wide-spread use of cost benefit analysis as a tool to evaluate publically funded investments, the exact same investment seen from the perspective of a private, profit-maximising investor will generate significantly different returns to investment than when viewed by the public sector investor. Subsidies and taxes can therefore be seen as tools used by the public sector to modify the returns to investments perceived by the private investor. Assuming that support schemes are a way for governments to reward investments which maximise welfare, how clearly is this translated from the public sector to the private sector? To what extent do the public sectors efforts to internalize positive and negative externalities influence the private investors return to investment?

The introduction provides a brief introduction to the background material motivating this thesis. Chapter 1 is a joint paper written with Professor Scholtens assessing differences in Danish and Dutch cost benefit analysis methodology using the same case study in Denmark and the Netherlands. Chapter 2 looks at ranking bias in capital investment comparisons when using the internal rate of return, net present value and the profitability index to assess energy investments. Chapter 3 looks at probable bias issues from using the internal rate of return to rank energy investments in more detail. Chapter 4 presents a comparison of the policies used to promote small-scale biomass CHP in Denmark, the UK and Germany. Chapter 5 is a jointly written paper with two engineering colleagues on trigeneration in UK supermarkets. Chapter 6 concludes with the final article, a joint paper written with Professor Bentzen on cointegration between biofuels, fossil fuels and agricultural feedstocks.

Sammenfatning

Denne PhD var motiveret af to spørgsmål. Det første spørgsmål var hvilket forhold finansiel støtte til vedvarende energi har med eksternaliteter at gøre og hvilke forskelle der er på tværs af landegrænser. Med andre ord, hvis en investering i et vedvarende energi anlæg resulterer i en nettogevinst for samfundet, er størrelsen af denne gevinst afspejlet i værdien af den støtte der gives? Bruges støtteordninger til vedvarende energi som en måde at internalisere positive eksternaliter på samme måde som forhøjet afgifter bruges for at korrigerer negative eksternaliteter?

Det andet spørgsmål er en naturlig forlængelse af det første. Givet at en regering anvender støtteordninger målrettet specifikke teknologier med en samfundsøkonomisk nettogevinst, i hvor høj grad er denne gevinst værdisat og overført til investorene, d.v.s. hvordan bliver en samfundsøkonomisk gevinst overført til den private sektor for at stimulere de mest samfundsøkonomiske fordelagtige investeringer?

Introduktionen giver et overblik over ErhvervsPhD-forløbet og baggrundsmaterialet brugt i denne artikelsamling. Kapitel 1 er en artikel skrevet med professor Scholtens, omhandlende danske og hollandske forskelle i cost benefit analyse metodik, vist ved brug af den samme case-studie i Danmark og Holland. Kapitel 2 illustrerer skævheder i sammenligninger af energiinvesteringer ved brug af kapitalinvesteringsberegninger som den interne rente, netto nutidsværdi og profitability indekset. Kapitel 3 ser nærmere på skævheder ved brug af den interne rente til at bedømme investeringsafkast i energiinvesteringer. Kapitel 4 sammenligner støtte til fremme af mindre biomass-kraftvarmeanlæg i Danmark, Storbrittanien og Tyskland. Kapital 5 er skrevet i samarbejde med to tidligere ingeniørkollegaer om anvendelsen af trigeneration (kraft-varme-køling) i britiske supermarkeder. Kapitel 6 afslutter med en artikel skrevet med professor Bentzen om cointegration mellem biobrændstoffer, fossile brændstoffer og organiske råmaterialer.

Introduction

Physical framework of the Industrial PhD Program

This section describes the physical framework of the Industrial PhD project registered as project number 10-078108 at the Danish Agency for Science, Technology and Innovation.

The purpose of the project is to investigate how important policy support in the form of economic incentives is to the renewable energy industry, by examining the progress of a market leader-in-the-making, Stirling.DK Ltd. At the time of the start of the project, August 2010, the company had launched several pilot projects in different countries, had approx. 25 employees and had not yet achieved break-even status in the revenue stream. Their core product is an adapted Stirling engine, one of the earliest engine types ever built, which has been modified to run on gasified biomass instead of natural gas. The engine had been tested in excess of 15,000 hours by 2010 and the company was expecting a strong capital injection before ramping up production and sales.

In order to fully capitalize on my value to the company, I was awarded the mid-level management position "Head of Marketing" three months after beginning the project. My position was well suited for the requirements of the Industrial PhD, focusing on expert understanding of the markets for RETs in the company's core markets and disseminating to both internal and external audiences. I reported directly to the CSO, Mr Svend Erik Christesen.

At the request of my host company, Stirling.DK Ltd., I took a leave of absence for a period of six months from 01 May 2011 to 01 November 2011, eight months into my PhD project. This was directly motivated by the level of insight I had gained during the preceding eight months. The purpose of the leave of absence was to support the CEO, CFO and CSO in securing capital for the further development of the company.

We were unsuccessful in attracting new investors to the company, but the existing investors agreed to continue financing the company until the next funding round could be started. I returned to my PhD research, but continued to work as Head of Marketing part-time. The CSO retired, and the following seven months culminated in the departure of the CEO. A new CEO was hired in the summer of 2012, at which point I asked to be relieved of my duties in the company to work full-time on my PhD for a period. Following a four-month adjustment process, I was granted leave to work full-time on my research starting in November 2012.

In February 2013, the company filed for bankruptcy. I spent some time looking for alternate financing until the Ministry of Science, Innovation and Higher Education agreed to finance the remainder of my PhD.

The market research conducted as the base of my academic work has been disseminated both externally and internally in the company. External dissemination has primarily taken place in the form of customer contact, either at meetings with existing or potential customers or at larger events such as conferences and trade shows.

The internal market documentation has been primarily focused on one product type, the solid-biomass combined heat and power (CHP) plants. Internally completed market reports include:

- Macroeconomic estimates of the European market potential based on available biomass resources, existing CHP deployment and the industry-wide shift to both decentralized generation and renewable resources
- Country specific estimates of the CHP potential for the UK and Germany, accounting for national policies, available resources and existing energy sector structure
- Sector specific estimates of the CHP potential for the UK retail sector, including an assessment of the opportunities and threats facing SDK CHP plants
- Customer economic models for Danish, German and UK customer, taking into consideration the specific national context and a selected product type

Overall research question and motivation

Policy support for renewable energy is an intensely debated, but integral part of any current energy policy. Optimal policy design is elusive, as the appropriate energy mix is highly dependent on local characteristics but is necessarily determined at national or even international levels. Increasing policy support for renewable energy reflects the assumption that an increased share of renewables in the energy supply brings about a net increase in welfare. Arguments both supporting and opposing this claim abound. The energy market is perhaps the perfect example of an imperfect market, where the magnitude and multitude of immeasurable spill-over effects is only rivalled by the social, political and economic necessity of a stable, affordable energy supply.

This paper is primarily concerned with market-pull or demand-pull policies rather than technology-push policies. Market/demand-pull policies are defined as policies which stimulate market demand for given technologies or resources, whereas technology-push policies are primarily concerned with stimulating technological innovation, e.g. through the use of research and development funding and pilot project support. Technology-push policies are discussed extensively in the literature elsewhere (for instance, see Olmos et al, 2012).

It is assumed that higher levels of policy support reflect stronger assumptions of the net social benefit resulting from greater diffusion of the technology in question, controlling for price differences in the technology considered. Countries with a greater share of natural resources in e.g. wind power would be expected to favour wind technologies in policy support as well. Alternatively, policy support could be determined by the wish to further national interests to develop and support national industry. Arguably greater levels of support are expected for more expensive technologies but the purpose of this dissertation is not to contribute to the extensive literature on this topic but rather on determining whether support is in any way correlated by the net social benefit expected from a given technology. To illustrate this, the dissertation considers only one technology type with applications in different countries. As the cost of the technology is the same across all countries differences in support levels is assumed to reflect other considerations.

A new body of empirical literature (Marques et al., 2010; Marques et al. 2011) examines the drivers of renewable policy support, and suggests that it is less motivated by climate change concerns and fossil fuel costs than by the presence of strong lobbying factions and national economic gains, either through improved energy balances or the stimulation of new national industry.

Renewable energy, in many cases, satisfies concerns on national energy security, environmental impact and local economic stimulation. The European Union (EU) is particularly invested in the promotion of renewable energy alternatives, with the Directive 2009/28/EC committing to a reduction in primary energy consumption, reduced greenhouse gas emissions and an increased share of renewables in the energy supply.

The technology considered in this Ph.D. is a new entry in the market with few suppliers and little direct competition (Carrara, 2010), which is assumed to reduce the level of bias from corporate lobbying on the level of policy support. Specifically, the high rates of policy support for both solar and wind technologies could be partially motivated by strong industrial lobbying factions as well as their perceived net benefit to society. By using a case study of a little-known technology, it is assumed that the level of policy support available primarily reflects the assumed net benefit such an application would bring.

Public policy incentives, such as feed-in tariffs, can address market failures in the energy industry by monetizing benefits from a public good and transferring them to a private consumer. Lack of internalization of external costs is a market failure particularly prevalent in the energy industry. Recent years have intensified the debate on stable, affordable energy supplies contra energy security and environmental issues arising from reliance on fossil fuels.

In order to address concerns over the future energy supply in Europe, the European Union (EU) has set the 20-20-20 climate and energy targets, specifically composed of:

- A minimum reduction of greenhouse gas emissions of 20% below 1990 levels,
- A 20% share of energy consumption to come from renewable energy sources
- A 20% reduction in primary energy usage, primarily from increased energy efficiency

All of these targets are to be achieved by 2020, for EU as a whole. Each country within the EU is bound by different targets, reflecting the starting level of each in 2007. Each country has been required to present a detailed action plan in accordance with Article 4 of the Renewable Energy Directive, summarizing the measures implemented to achieve their climate and energy targets by 2020.

Policy instruments such as energy quotas, feed-in tariffs and tax exemptions are key elements in securing a broad diffusion of renewable energy technologies (RET) in the marketplace.

This thesis argues that the current policy-centric discussions of various support mechanisms do not sufficiently capture the barriers to RET diffusion. The investment scenario seen from the eyes of an investor are notably different than that seen by a policymaker. This can sometimes lead to miscalculation in setting an appropriate level of incentives, leading to either over-subscription or under-subscription of the RET in question.

Additionally, this thesis tests an assumption that levels of public policy incentives are correlated with the perceived social benefit: the higher the given incentive, the greater the public benefit. Do socioeconomic public benefits transfer well to private parties, and what impact do the subsidies have on an individual’s investment decision?

A critical issue policy-makers address in public policy incentives promoting RET, is the relatively larger upfront capital costs required for RET investments relative to conventional energy technologies (CET). Most RETs combine large upfront capital costs with low running costs over time, where CETs tend towards lower upfront capital costs and higher running costs.

This characteristic increases the significance of the discount factor used in energy investment scenarios. Investors and consumers in general are more reticent when facing a higher initial investment than its closest alternative, even when the returns are demonstrably higher over time for the high-cost investment. The discount factor used in investment calculations can be adjusted to reflect this time preference.

CBA is one of the primary tools used by policy-makers to calculate the net social implications of new investments. This paper uses CBA in addition to return on investment calculations from the private and local perspective in order to assess what proportion, if any, of the net social benefit is transferred to the private investor.

All the calculations in this paper are based on state-of-the art applications of small-scale cogeneration based on biomass. The use of incentives in some form to shift consumption from CET to RET takes different forms dependent on political interests, available natural resources and other country-fixed effects.

Methodology and case study overview

The aim of this dissertation is to demonstrate the following two points;

1. Holding cost of the technology constant and assuming limited lobbying power, higher subsidies will reflect greater welfare gains. This is demonstrated by comparing the same technology as a case study in several countries. By holding the technology cost constant, the case studies reflect differences in national strategies aimed at promoting the diffusion of new renewable energy technologies. By using a relatively unknown technology type the influence of lobbying on the support mechanisms is assumed to be minimal, such that it is more likely to correlate with the net externality effect of the technology.
2. While much has been published on the subject of the use of taxes and subsidies to internalize externalities there is a relative dearth of literature on how these measures influence the decision to invest made by the private investor. This is especially critical for

renewable energy infrastructure, given that private investment into renewable energy sources is a necessity to satisfy the EU 20-20-20 targets.

CBA and capital investment measures will be used to demonstrate the impact of support schemes on the welfare impact and profitability of the same case study technology in Denmark, Germany, the UK and the Netherlands. Particular attention is paid to the different capital investment measures as these are not neutral across investment types and their use may result in systematic bias in the perceived profitability of renewable energy investments.

The same base technology is used in all the calculations. The technology considered is a biomass driven combined heat and power plant. This energy system is small and unique, a state-of-the-art energy system with high energy conversion efficiencies. The energy system uses a 35 kW Stirling engine coupled to a high temperature combustion chamber which in turn is fed from an updraft gasifier. The updraft gasifier is available in a 200 kW size for a 1-engine system and an 800 kW size for use with multiple engines. The system is designed as a baseload technology, i.e. it will operate between 7,000 and 8,000 hours annually. The primary fuel used is fresh woodchips of sufficient size and quality as specified by Stirling.DK Ltd. Unusually, the woodchips must have a very high moisture content, preferably around 45-55% moisture. This means that less processing (drying) is necessary which drives down both the carbon impact and the fuel cost.

Chapter overview

All of the chapters in this dissertation have been written as stand-alone papers. As such there will be a degree of repetition when reading the dissertation as a whole.

1. Chapter 1 applies country specific CBA guidelines to the same investment cases in Denmark and the Netherlands, a biomass CHP plant and two types of natural gas CHP plants. The countries were chosen for comparison due to their apparent similarities, which emphasizes the degree to which CBA methodology differs across national borders. Assuming CBA can be used by public policy decision-makers to value externalities we would expect correlation between the value of support schemes and the net magnitude of externalities.

2. Chapter 2 pays particular attention to the most widely used capital investment measures. As mentioned earlier, the most common capital investment measures; net present value, internal rate of return and profitability index, are not neutral across investment magnitudes,

particularly when comparing investments with different proportions of initial investment costs and operating costs. As many renewable energy systems share characteristics of high initial investments followed by low operating costs compared with their closest fossil fuel substitute, these biases may skew public opinion with regards to their relative profitability.

3. Chapter 3 continues the work carried out in Chapter 2 but is focused solely on the internal rate of return. The author believes that additional attention is needed in this area because despite decades' worth of academic consensus on the limitations of this capital investment measure, it continues to be widely used particularly when comparing across dissimilar investment types. These limitations are particularly damaging to the reputation of the financial viability of renewable energy systems.

4. Chapter 4 provides a case study of the impact of current schemes in Denmark, Germany and the UK on the financial viability of a small-scale biomass energy technology. This paper looks at how financial support schemes affect the decision of the investor to invest or not invest, compares the impact on the investment decision across Denmark, Germany and the UK and discusses the significance of the financial support schemes relative to the existing market conditions. Although the technology application is the same in all three cases, the structural differences between the three countries results in differences in the amount and type of support offered, and also differences in the financial viability of the technology in the situation where no support is offered.

5. Chapter 5 is a collaboration with two former engineering colleagues on the technical and financial benefits of installing a biomass CHP system in two UK supermarkets. Supermarkets are intensive energy users, particularly with respect to heating and cooling. A trigeneration system producing electricity, heating and cooling generated onsite using local woodchips would provide significant monetary and environmental improvements. The additional welfare gains from generating cooling onsite are not directly addressed directly through the support scheme and so the decision to invest in this add-on is primarily motivated by cost savings.

6. Chapter 6 is jointly written with Professor Jan Bentzen. The paper addresses concerns in whether the price movements of biological oils (biofuels) influence or are cointegrated with food stocks and/or fossil fuel prices. This paper is a departure from the overall research

questions addressed although it does generally follow the comparison of renewable and fossil fuel alternatives under the EU 20-20-20 ambition.

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Chapter 1. A comparison of cost-benefit analysis of biomass and natural gas CHP projects in Denmark and the Netherlands

Paper status

Authors: Tanja Groth and Bert Scholtens

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1.1 Abstract

We investigate what drives differences in project appraisal of biomass and natural gas combined heat and power (CHP) projects in two countries with similar energy profiles. The purpose is to demonstrate differences in national approaches to cost benefit analyses (CBA). Therefore, we use CBA to assess the same project proposal for Denmark and the Netherlands, following the respective state guidelines to demonstrate that the sensitivity of the CBA results not only from natural variations from country to country, but also from discrepancies in the methodology used. Finally we compare the NPVs generated to the available subsidy level for the biomass CHP project in order to assess whether there might be a correlation between net social benefit and support schemes.

1.2 Introduction

If we assume that government support is necessary due to inherent market failures in energy markets, notably, the emission of greenhouse gases, then this level of support should in some way relate to the size of these market externalities not accounted for in these markets. One way to determine the value of such externalities is to perform a cost benefit analysis (CBA) on a given energy project to estimate what monetary and non-monetary costs and benefits are generated outside the direct transaction between the supplier and the buyer.

CBA is commonly used in public projects, with some member states providing manuals such as the "*Green Book*" in the UK (HM Treasury, 2003), the "*Vejledning for Samfundsøkonomiske analyser på energi-området*" in Denmark (Danish Energy Agency, 2007), and on the EU level, the EC's "*Guide to cost benefit analyses of investment projects*" (2008). The advantage of an officially sanctioned manual for public projects is that it sets out clear steps for performing an investment analysis appropriately weighted by socioeconomic factors, such as environmental externalities, valuation of non-traded resources such as land, and regional wage distortions.

CBA guidelines for electricity infrastructure, gas infrastructure and smart grids are currently being refined by the EC in order to address trans-European energy infrastructure projects (Meeus et al., 2013). Existing literature on the use of CBA to assess welfare impacts in an international context is found primarily in the general social studies branch, which considers CBA to be a form of horizontal regulatory cooperation (Alemanno, 2013). In this literature, divergent CBA practices give rise to indirect barriers to trade and a reduction of economic efficiency.

Clearly, disparities in CBA methodologies from state to state are already recognized by the EC, which explains the necessity of formulating guidelines for transnational projects. The purpose of this paper is to demonstrate the extent of any disparity between two EU states, the Netherlands and Denmark, by applying their respective CBA methods to the same case study. By using the same case study in both states, any significant differences in the CBA results are a result of either natural variance between the two states or discrepancies in the CBA method itself.

Section 1.3 presents the materials and methods employed in calculating the CBAs for Denmark and the Netherlands, respectively and an overview of the similarities in their respective energy profiles. Section 1.4 contains the results for each country and a comparison of the two, as well as the impact of a sensitivity analysis on the results. Section 1.5 discusses factors influencing the results. Section 1.6 concludes with policy implications.

1.3 Materials and methods

Background

A key criticism of determining support schemes at the central EU level is that each state has different geographical, legal, political and market conditions which influence the optimal level of renewably sourced electricity. Ideally, a common framework would result in overall cost savings with favourable conditions for sites with comparative advantages, e.g. wind farms in areas with high average annual windspeeds, but it might also result in unacceptable high rents being earned at the most advantageous sites (Resch et al., 2013).

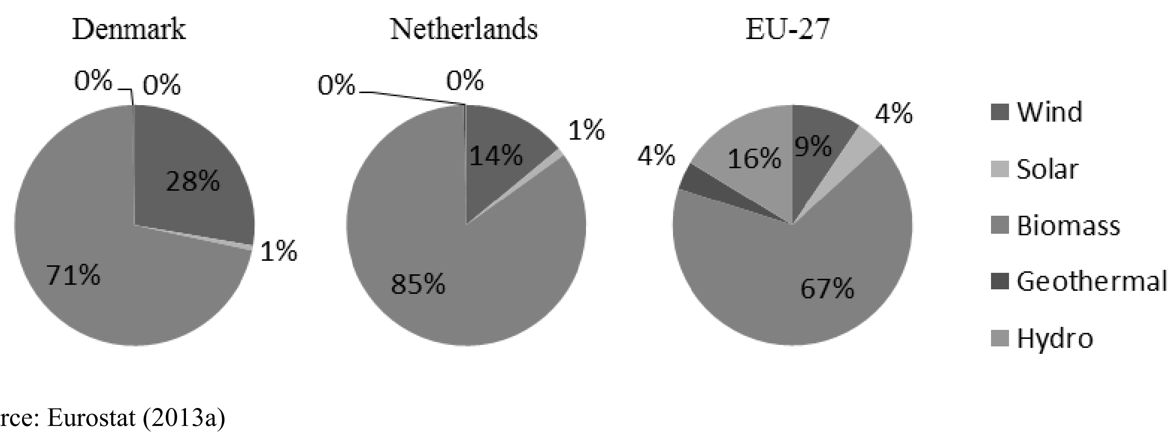
These differences in conditions between states should be reflected in the socioeconomic values for economic externalities – positive and negative – set for CBA's of public projects. What drives differences in socioeconomic values between countries? Willingness to pay for environmental amenities is shown to increase for higher income levels and greater levels of public acceptance of renewable energy (see for instance, Batley et al., 2001 and Zarnikay, 2003). Greater willingness to pay for environmental amenities is assumed to bleed over into higher public policy support for environmental amenities, at least in democratic countries. Presumably, the more similar the geographical, legal, political and market conditions between two states, the more similar the socioeconomic weights attached to certain externalities. Therefore we would expect higher subsidy levels where the socioeconomic benefits are perceived to be greater, holding technology costs constant.

Regional differences in land costs, electricity prices etc. are ignored in favour of using national averages in order to provide more comparable results. Natural variations between states in, for instance, electricity prices are assumed to reflect national priorities and comparative advantages. It is interesting to determine whether any differences between the two calculations primarily are motivated by natural variations in price levels and energy costs or whether the differences are driven by monetary estimates of e.g. greenhouse gas emissions. This will be discussed in more detail in the results section.

Choice of Denmark and the Netherlands for comparison

The energy profiles of Denmark and the Netherlands share a number of common characteristics, such as substantial natural gas fields and an abundance of biomass and wind resources. Figure 4.1 shows the comparison of renewable energy shares measured in 1,000 tonnes of oil equivalents from 2011.

Figure 1.1 Shares of renewable energy primary production measured in 1,000 tonnes oil equivalents for 2011 for Denmark, the Netherlands and the EU-27 as a whole



Source: Eurostat (2013a)

The figure shows negligible shares of geothermal and hydro energy sources for both Denmark and the Netherlands, with 0% registered shares for each of these in both countries after rounding to the nearest whole number. Likewise solar energy is a minor contributor, with only 1% share in the renewable energy primary production for each country. In contrast, for the EU-27 as a whole, geothermal and hydro energy represent 4% and 16%, respectively, and solar energy an additional 4%. Primary renewable energy production in Denmark and the Netherlands is instead dominated by relatively large shares of biomass (including waste) and wind power.

A second similarity in the energy profiles of the two countries is the high share of combined heat and power (CHP) generation, measured as a percentage of gross electricity generation. For Denmark the average share for 2011 was 46.2%, with corresponding values for the Netherlands and the EU-27 at 32.5% and 11.2%, respectively. The shares for CHP generation in the Netherlands and Denmark are substantially larger than in the EU as a whole, with only Latvia, Lithuania and Finland showing similar CHP prevalence (Eurostat, 2013b).

A final similarity relevant for this paper is the natural gas energy profile for the two countries. Relative to primary natural gas production in 2011, the share of imports was 5% for Denmark and 29% for the Netherlands, compared with 251% for the EU-27 as a whole. Gross inland consumption was 59% of primary production for both countries, while it was 284% for the EU-27. Both countries are net exporters of natural gas, and consumption does not exceed production in either country, unlike for the EU-27 as a whole (Eurostat, 2013c).

To sum up, the share of renewable energy is predominantly sourced from biomass and waste for both Denmark and the Netherlands, with wind being the other main contributor. Both countries have significantly higher shares of CHP generation than the EU-27 as a whole, and both countries are net exporters of natural gas. With these similarities in mind, this paper compares a biomass CHP system with a natural gas CHP system. The physical size of the system is small, such that it is not automatically included in the EU Emissions Trading System (ETS).

CBA analysis

A CBA can be used to estimate the net social benefit or excess social benefit over cost generated by an investment ex ante. This net social benefit is sometimes referred to as a potential Pareto improvement, i.e. there is an increase in benefits accrued to the society greater than the corresponding increase in costs. In order to estimate this fully, not only goods already traded in market conditions but also goods which are unpriced must be estimated, and where feasible, a price assigned to the untraded goods in order to generate a net single figure referred to as the net present value (NPV). The CBA must always consist of a comparison with an alternative or existing scenario; in this paper, the biomass CHP is compared against two alternative natural gas CHP systems. A positive NPV will therefore indicate that the biomass CHP results in a net increase in welfare relative to the natural gas CHP systems and vice versa.

Key elements of the CBA in this paper include:

- Price level, discount rate and time horizon
- Investment, maintenance and land costs
- Fuel costs and price projections
- Treatment of subsidies and taxation
- Emission estimates and valuation

These elements are described further below and key figures are summarized in a table at the end of this section.

Price level, discount rate and time horizon

In this study, all prices are reported in real prices, at the 2011 price level. The Danish Krone (DKK) is set at 7.46 against the Euro, but there are costs involved in exchanging, so the exchange rate is rounded upwards to DKK 7.5 per Euro (ECB, 2013).

The original Danish social discount rate of choice for cost benefit analyses in the energy area was 6% (Danish Energy Agency, 2007). Recently, however, the Danish Ministry of Finance released a note on discount rates to be used in future socioeconomic analyses, recommending that a 4% rate is used for analyses conducted in the time horizon 0-35 years, dropping to 3% for years 36-70 and 2% for the years following (Danish Ministry of Finance, 2013)[2]. As the original discount rate was also based on a recommendation from the Danish Ministry of Finance, the 4% rate, consisting of a 2% risk-free rate and a 2% risk premium, is used for the Danish calculations in this paper.

The latest missive from the Dutch Minister of Finance on the appropriate discount rate for public investments recommends a discount rate of 5.5% or 4%, consisting of a risk-free rate of 2.5%, with

[2]The recommendation follows from a Norwegian public report published in 2012, and the social discount rate consists of a 2% risk-free rate and a risk premium of 2% for projects with low systemic risks. (Norway's public reports, 2012)

a risk premium of 3% in the general case and a risk premium of 1.5% when valuing specific negative externalities of an irreversible character (Dutch Ministry of Finance, 2011). These rates were most recently used in a CBA of 6000MW onshore wind developments by the Dutch Central Planning Bureau (CPB) (Verrips et al., 2013), where the 5.5% rate was used for the general analysis and the 4% rate was used to value emissions with a negative impact on the environment.

The recommended social discount rate from the European Commission's *Guide to cost benefit analysis of investment projects* (2008) is 3.5% for Denmark and the Netherlands as well as the other mature economies within the EU, and is partially derived from per capita growth rates. Particularly for renewable energy investments, where the benefits accrue over a long lifetime while the costs are mainly upfront, a lower discount rate will have a significant impact on the net balance. That both Denmark and the Netherlands have higher discount rates (4% for the long term) than recommended (3.5%) hints at an undervaluation of long-term externalities.

The time horizon used in the analysis is based on the expected technical lifetime of the biomass-based CHP solution used in the reference scenario, set at 15 years (Danish Energy Agency, 2012a). Assuming a contract is signed in the beginning of January 2014 and a six month delivery and installation time, the plant will run from mid-2014 to mid-2029.

Project scope

The choice of baseline is very important in CBA. In order to demonstrate this, the reference scenario is contrasted with two baseline scenarios. The reference scenario consists of a small-scale woodchip powered CHP, while two alternative baseline scenarios are considered. The first is an electric spark ignition engine (natural gas engine CHP) and the second is a mini single cycle gas turbine (natural gas turbine CHP), both of which run on natural gas and are also CHP systems. The technical data is taken from *Technology Data for Energy Plants*, published by the Danish Energy Agency (2012a). These two technologies were chosen as their technical data was readily available and they exist in a comparable size range relative to the biomass CHP system.

The economic agent profiled in the case study is an industrial greenhouse owner who uses process heat to grow vegetables for market consumption. The average physical size for a greenhouse in Denmark is 4,000 square meters (sqm) and a greenhouse owner will typically have six of these. To grow vegetables requires a temperature of 18 degrees Celsius, roughly equal to 2,800 MWh of heat and 70 MWh of electricity annually. Greenhouse owners use natural gas boilers, natural gas CHP units or a combination of these two to provide energy to the greenhouses (Hortiadvice Scandinavia A/S, 2009).

It is assumed that the natural gas systems can be installed in the existing buildings as a replacement for the system in operation, while in this case study the biomass system must be installed greenfield, i.e. on new land with new buildings. This is partly to account for the much larger area required to house the woodchip fuel in contrast to natural gas, which has a much higher energy density (Stirling.DK Ltd., 2012).

In the Danish case study, it is assumed that a greenhouse owner wishes to test a biomass CHP system in one of the greenhouses. This is partly motivated by the Danish greenhouse association HortiAdvice Scandinavia A/S, which works with Danish greenhouse owners to test carbon neutral solutions for 2017, and partly by the Danish government offer of tax breaks and subsidies for carbon neutral energy solutions.

The Dutch greenhouse industry is roughly thirty times larger than the Danish one when measured by sqm, but an average Dutch vegetable grower has a comparable greenhouse area, capable of fitting up to seven greenhouses of 4,000 sqm. Much like the Danish sector, energy demand is primarily fuelled using natural gas (van der Meulen et al., 2011). Given that the sizes and energy profiles are quite similar, it is assumed that energy consumption for the same types of vegetables is similar as well.

In 2008, the Dutch agricultural industry signed a sector-specific agreement with the government to increase energy efficiency by 2% annually and to aim for a renewable energy share of 20% by 2020 (Ministry of Agriculture, Nature and Food et al., 2008). The sector scheme mimics the setup of the EU emissions trading scheme (ETS) without being a formal part of it, in return for investment subsidies and a reduction in energy taxes.

As heat is the primary energy output the greenhouse owner is interested in, all the plants are sized according to their heat output rather than their electric output. Natural gas CHP systems have a higher electric efficiency, so while the heat capacity of the biomass CHP systems (420kW) is slightly higher than that for the natural gas units (360kW and 385kW), the electric capacity of the biomass unit is significantly lower (105kW compared to 300kW for the natural gas systems) (Danish Energy Agency, 2012a).

It is assumed that the extra electricity produced by the natural gas CHP systems was sold to the grid previously, but with the biomass CHP system, all electricity produced is used onsite instead. The costs/benefits of the change in grid balancing itself is ignored in this paper as the unit capacities are so small that any change in the grid balancing costs from the reduced sale of electricity to the grid will be minor.

Investment, maintenance and land costs

The biomass CHP system will be installed as a greenfield investment, that is, built on a site located near the greenhouse where there are no previous installations. For the sake of simplicity, we ignore the costs of extending the grid infrastructure, but an estimate of the building costs to house the biomass CHP unit is included. This is obtained directly from the manufacturer, Stirling.DK Ltd. (2012), and covers the costs of installing the equipment in a series of standard-sized shipping containers, ready to be placed on site.

In order to cover the average estimated heat demand of the greenhouse, the owner has decided to invest in a 105kW electric biomass system, which will provide 420kW heat, enough to cover the estimated average annual heat needs +15% at full load production. The investment costs of the comparable natural gas engine CHP, the natural gas turbine CHP and the biomass CHP are shown in Table 1.1.

Table 1.1 Investment costs of the three units

Total cost of biomass CHP unit, installed (including buildings)	Total cost of natural gas engine CHP unit, installed (excluding buildings)	Total cost of natural gas turbine CHP unit, installed (excluding buildings)
€707,500*	€450,000*	€630,000*

*All prices are given at the 2011 price level. Source: Danish Energy Agency 2012a, verified by internal company estimates from Stirling.DK Ltd.

Operation and maintenance (O&M) costs are technical costs and constant regardless of whether the unit is located in Denmark or in the Netherlands. Basing annual operation hours on the heat demand, both the natural gas systems would operate at 95% of the year at full load, while the biomass system would operate at 87%. The corresponding annual O&M costs are 20% lower for the biomass system than for the natural gas system (Danish Energy Agency, 2012a).

We would expect some labour costs on the side of the greenhouse owner, both in the installation phase and the operation phase of the plants, but for this analysis these costs have been excluded. Wage costs tend to differ from region to region in a country as well as from country to country. However, the purpose of this CBA comparison is not to present a full account of the differences between the three technologies included. Rather, the purpose is to compare the existing practices of the two countries in terms of weighting externalities not covered by direct market transactions and to assess whether the value of the subsidies are comparable to any calculated net benefit. However, any additional labour costs arising from installing the biomass CHP system have been normalized relative to the natural gas CHP installation, such that the relative magnitude of the excluded labour costs is the same in both scenarios. This additional cost is included in the investment figure in Table 1.1.

The fraction of labour costs for annual operation paid by the greenhouse owner is estimated to be minor, consisting of a couple of hours weekly, due to the fully automatic nature of the three technologies. While these costs should be included in a full CBA of such a project in "real life", for the purpose of this analysis they are judged unnecessary.

There is a change in land use from switching from the natural gas systems to the biomass system, equal to the land costs necessary for housing the new energy system plus woodchip storage. Land cost estimates for the Dutch case are derived from the direct cost estimates in Bruinsma et al. (2002; Table 6), and inflated to the 2011 price level. Land cost estimates from the Danish case are borrowed from average alternate use estimates in a recent CBA of biogas installations (Jacobsen et al., 2013).

Fuel costs and price projections

Benefits from operation are partially dependent on price projections for electricity and natural gas. These benefits do not include socioeconomic benefits, which are dealt with later on in this paper.

The biomass system uses a small amount of natural gas for start-up and then switches to woodchips. The natural gas systems only use natural gas. The amount of natural gas used in the biomass systems for a start-up is very small (less than 1% of total fuel use) and is therefore ignored in this analysis (Stirling.DK Ltd., 2012).

There are no official Dutch statistics on wood fuel prices (Vinterback & Porso, 2011). Instead, cost projections have been taken from an EU report providing an illustrative case study of woodchips supplied to the Netherlands (Hoefnagels et al., 2011, Figure 4-1). These woodchips are provided as factor price estimates including cultivation, harvesting, storage and transportation but excluding taxes. These prices are modified using a net tax factor of 1.166 (Zwaneveld, 2011).

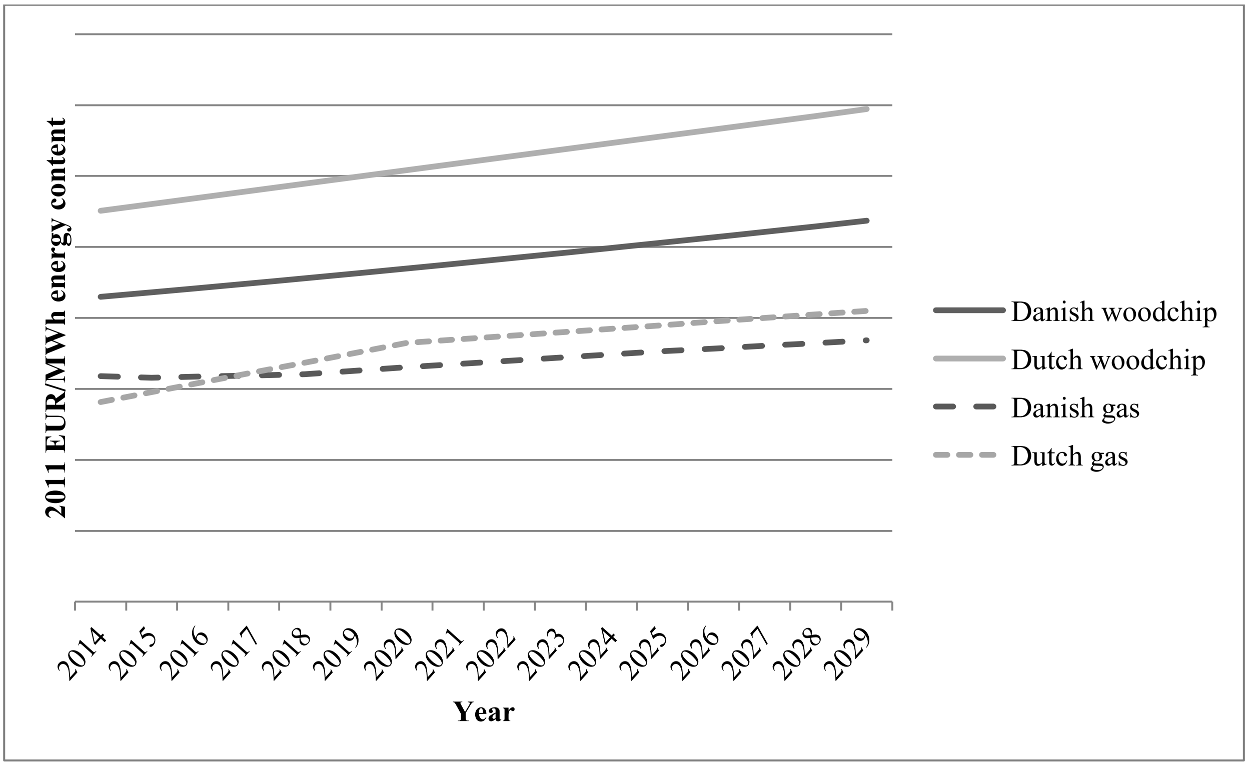
Danish woodchip price projections are provided by the Danish Energy Agency, including socioeconomic estimates of transport and storage costs up to the delivery point. These prices are provided as factor prices and have subsequently been adjusted using a net tax factor of 1.17 (Danish Energy Agency, 2012b).

Natural gas prices for the Netherlands are based on IEA 2010 projections (Koelemeijer et al., 2013) while natural gas prices for Denmark are based on IEA 2011 projections (Danish Energy Agency, 2011). The Dutch prices were only available for 2010, 2020 and 2030; linear interpolation was used to provide estimates for the other years. The Danish prices are available including estimates of transport and storage costs up to the delivery point. None of the reviewed literature provided similar estimates for the Dutch prices, so these modifications are ignored in the analysis in favour of using comparable values. Both are adjusted with their respective net tax factors, as are the woodchip prices.

Finally, the prices per cubic meter of natural gas were converted according to national estimates of the energy content of the fuel; 31.65 MJ/Nm^3 for the Netherlands (Vreuls & Zijlema, 2011) and 39.51 MJ/Nm^3 for Denmark (Danish Energy Agency, 2012b).

The fuel cost prices for both woodchips and natural gas are given in Figure 1.2.

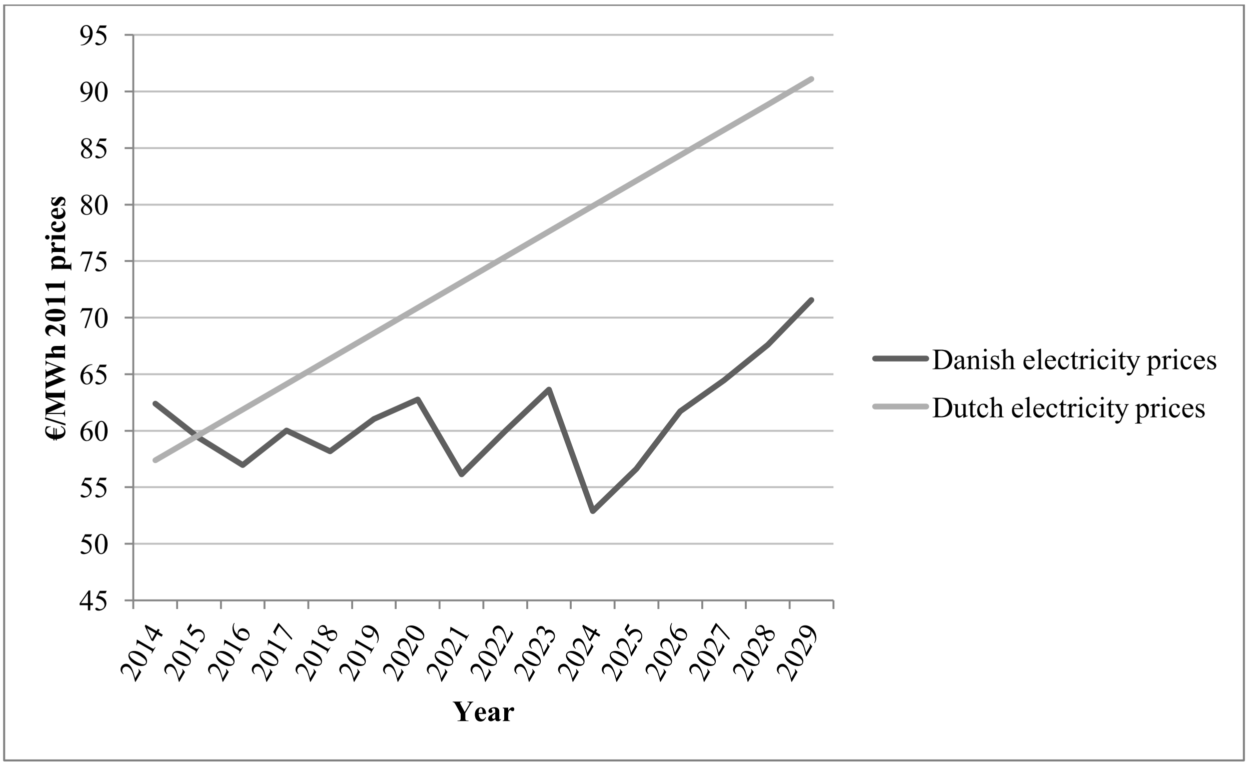
Figure 1.2 Woodchip and natural gas prices for Denmark and the Netherlands, 2013-2030



Prices in 2011 levels and adjusted for the net tax impact factor. Source: Hoefnagels et al., 2011 Figure 4-1; Danish Energy Agency, 2012b; Koelemeijer et al., 2013; Danish Energy Agency, 2011.

For electricity prices, the Danish price projection is taken from the Danish Energy Agency (2012b), which in turn is based on the IEA World Energy Outlook New Policies Scenario 2011. The Dutch price projection is based on the background data used to evaluate the Dutch energy agreement (Koelemeijer et al., 2013). Both projections are in factor prices and adjusted with their respective net tax impact factors. Unfortunately, only data for 2014 and 2020 for the Dutch projection were released to the general public, so the remaining data has been derived on the basis of linear interpolation, which explains why the line is smoother than for the Danish price projections in Figure 1.3. However, after the net tax impact factors, the values correspond roughly with the price projections used in the recent public CBA analysis of a 6,000MW wind farm (Verrips et al., 2013).

Figure 1.3 Electricity price projections for Denmark and the Netherlands, 2013-2030



Prices adjusted for net tax impact factor of 16.6% for the Dutch case and 17% for the Danish case. Source: Danish Energy Agency (2012b); Koelemeijer et al., 2013

In the reference scenario, the system is fuelled by biomass gasified onsite, which is combusted directly in the CHP unit. No woodgas is upgraded and exported to the biogas grid. Excess electricity is exported to the grid for balancing purposes. In the alternative scenarios, excess electricity produced by the natural gas unit is sold to the grid, giving rise to energy income. It is assumed there are no grid integration issues with replacing the existing natural gas unit with a new one for either country.

Treatment of subsidies and taxes

Subsidies and taxes are not included in the calculations, as they are transfer payments and therefore generally kept out of socioeconomic calculations. The exception to this is to include them in a calculation of the deadweight loss, which estimates the costs to society of financing changes in the tax base, such as for differences in subsidies and taxes between scenarios (Zwaneveld, 2011; Danish Energy Agency, 2011).

In Denmark the social deadweight loss is calculated by multiplying changes in the tax base by 20% (Danish Energy Agency, 2007). Noteworthy taxes are the energy tax on natural gas ("energiafgift"), the energy savings tax ("energispareafgift", previously the carbon dioxide tax) and taxes on emissions of Nitrogen Oxides (NOx) and Sulphur dioxide (SO2). Note that the effects of these taxes are likely to be minor, especially since greenhouse owners are exempt from 98.2% of the energy tax on natural gas (Skat, 2013).

In the Dutch literature reviewed, the only reference found for this practice was in a note published by the CPB, Netherlands Bureau for Economic Policy Analysis from 2011. The author states that additional tax revenue or reduced government spending should be included in calculations of social CBA and welfare effects, but unlike the case of the net tax impact factor, no value for estimating the social deadweight loss resulting from such changes was given. Likewise there was no mention of this practice in the Dutch CBAs reviewed, so it is clearly not common practice and therefore excluded from the Dutch CBA case in this analysis.

Subsidies are not included in the CBA but the final NPV will be compared to the level of subsidy available for the biomass CHP system. Difference in socioeconomic weighting of e.g. emission costs might carry over to support levels available for technologies which reduce said emissions. As the biomass CHP technology is the same for both countries any difference in support levels will most likely be ascribed to either lobbying or a perceived net social benefit.

In Denmark, industrial energy producers can choose between a subsidy covering upfront investment costs or a feed-in tariff supporting electricity fed into the grid. As this CHP unit produces correspondingly more heat per unit of electricity, all of which is used onsite, we would expect the greenhouse owner to apply for the upfront capital subsidy.

The upfront capital subsidy is valid for investment costs exceeding a conventional energy alternative, up to a maximum of 65% of the whole investment cost for small industries or DKK 23 per GJ fossil fuel replaced over a 10-year period (Danish Energy Agency, 2013b).As the difference in costs of the two installations is less than 65% of the total biomass CHP unit, it is expected that the Danish greenhouse owner will get the full difference subsidized.

The relevant subsidy in the Dutch case is the "Stimulering Duurzame Energieproductie" (SDE), in this case given per natural cubic meter (Nm3) gasified biomass converted into heat and electricity, for a maximum of 12 years and up to 7,500 hours annually. The base rate is modified according to year. A conservative estimate is taken by modifying the applicable Phase 1 value by the annual adjustment factor for 2013 and expressing it in 2011 values.

Emission intensity estimates and valuation

The volume of the gasified biomass is calculated by multiplying the energy content of the wood gas (5.3 MJ/Nm3) by the hourly volume combusted at full load, equivalent to 600 kWh or 2.16 GJ (Stirling.DK Ltd., 2012). The volume comes to roughly 407.6 Nm3 per hour of full load combustion.

The amount of emissions associated with each generated unit of energy (emission intensity) depends not only on the fuel type but also on technology characteristics of the energy plant used (Danish Energy Agency, 2011). The technology-specific emission intensities published by the Danish Energy Agency (2012b) are based on existing plants and therefore do not accurately reflect new plants. The emission intensities of electricity are location-specific, as emissions will reflect the fuel types and generation efficiencies of the energy generation sites. The emission intensity of natural gas should be similar across borders, although this may change if biogas is increasingly mixed with natural gas in the gas pipelines.

The CO2 emission intensity of natural gas is closely linked with its methane content. Methane content may differ from gas field to gas field. Here, the emission intensity of natural gas is roughly the same for the Netherlands and Denmark, with the Danish gas releasing 56.7 kg/GJ and the Dutch gas releasing 56.6 kg/GJ. The Danish values can be found in the Danish Energy Agency database (2012b) while the Dutch values are based on values from Vreuls and Zijlema (2011).

There is no EU-wide consensus on how to value the social costs of CO2, but there is an EU-wide Emissions Trading System (ETS) with a common platform for the majority of the EU members including Denmark and the Netherlands. From 2013, emission allowances for power generation are mainly allocated via auctioning, estimated to cover 40% of allowances in the system in 2013 and increasing up to 2020. While neither the Danish nor the Dutch greenhouse owner in this scenario falls under the scope of the ETS (European Commission, 2010), the quota prices have been chosen as a proxy for shadow prices. However, the ETS only extends to 2020, so national assumptions have been used to extend the CO2 estimates after 2020.

The Danish Energy Agency follows the CO_2 quota estimates reported by the International Energy Agency (IEA) to value avoided emissions (Danish Energy Agency, 2011).

In the recent CBA of the 6000 MW onshore wind energy project, the Dutch CPB provided an overview of CO2 values in the literature (Verrips et al., 2013). They used estimates of the damage from CO2 emissions post 2020 to valuate positive externalities from building additional wind turbines in the event that the ETS was not extended further. For this case study, the values from Koelemeijer et al. (2013) are used.

The price ranges from the 2012 Danish estimates (Danish Energy Agency, 2012b) and the values used in Koelemeijer et al. (2013) are given in Table 1.1.

Table 1.1 Projected CO2 quota values for Denmark and the Netherlands

2011 €/ton	2014	2020	2025	2029
Danish CO2 values[1]	12.07	25.31	29.53	32.90
Dutch CO2 values[2]	5.97	9.07	12.83	15.83

[1]Danish CO2 values have been changed from factor to market prices and exchanged to EUR
[2]Dutch CO2 values have been changed from factor to market prices deflated from the 2013 price level to 2011 price level using the Dutch CPI

The CO2 values differ significantly in magnitude from Denmark to the Netherlands, the Danish values being between twice and three times the Dutch values. Other greenhouse gas emissions commonly considered alongside CO2 are N2O (nitrous oxide) and CH4 (methane). Following from the 2006/2007 IPCC guidelines, the damage from 1kg of emitted CH4 corresponds to the damage from 25 kgs of CO2 while the damage from 1 kg of N2O equals 298 kgs of CO2 (Danish Energy Agency, 2013a). The same figure for CH4 was obtained from de Bruyn et al. (2010a), while no corresponding figure for N2O was obtainable from the Dutch literature reviewed here. However, it is assumed that the Dutch N2O damage assessment is in line with the IPCC guidelines.

Other emissions associated with energy generation relevant for this case study are Sulphur Dioxide (SO2), Nitrous Oxide (NOx) and particulate concentrations, PM2.5 and PM10. In the Danish guidelines, only PM2.5 is valued, whereas both PM2.5 and PM10 are valued in the Dutch guidelines (de Bruyn et al., 2010b). However, as they are given the same value, they will be considered interchangeable in this paper.

The emission intensities of the above greenhouse and non-greenhouse gases, excluding CO2, are technology-dependent so only the values from the technical characteristics in Danish Energy Agency (2012a) are needed. These are given in Table 1.2.

Table 1.2 Emission intensities of CHP units studied

g/MWh	CH4	N2O	SO2	NOx	PM
Natural gas-fuelled CHP	1674	2.16	1.08	486	0.58
Woodchip-fuelled CHP	11.16	2.88	6.84	423.36	11.16

Values are from Danish Energy Agency (2012a, 2012b)

The values of avoided emissions of SO2, NOx and PM2.5-10 shown in Table 1.3 are based on estimated damage costs provided by the Danish Energy Agency (2012b) and the independent research organization, CE Delft (de Bruyn et al., 2010a). The Dutch values are available as a range whereas the Danish values are only given as a single figure.

Table 1.3 Summary of key assumptions applied in CBA

Assumption	Denmark	Netherlands
Price level	2011 Euros	2011 Euros
Discount rate	4%	5.5% (4%)
Woodchip cost (2014)	43.0 EUR/MWh	47.3 EUR/MWh
Natural gas cost (2014)	31.8 EUR/MWh	24.2 EUR/MWh
Electricity value (2014)	62.4 EUR/MWh	57.4 EUR/MWh
Heat value (2014)	36.1 EUR/MWh	27.5 EUR/MWh
Deadweight social loss	20%	N/A
CO2 emission value (2014)	12.1 EUR/ton	6.0 EUR/ton
SO2 emission value[1]	12.6 EUR/kg	5.2-10.5 EUR/kg
NOx emission value[1]	6.5 EUR/kg	5.2-10.5 EUR/kg
PM 2.5/10[1]	15.0 EUR/kg	2.4-52.4 EUR/kg

[1]Dutch values originally in 2008 prices but inflated using the Dutch CPI. Values are from the Danish Energy Agency (2012b) and de Bruyn et al. (2010a)

1.4 Results

Table 1.4 provides the results of the NPV calculations for the reference scenario (biomass CHP) minus the alternate scenario (natural gas engine CHP). A positive result indicates that the reference scenario provides greater net benefits than the alternate scenario; in this case the reference scenario is the biomass CHP and the alternate scenario is the natural gas engine CHP.

Table 1.4 Net present values for the biomass CHP system minus the natural gas engine CHP

2011-EUR	NPV	Discount rate
Denmark	66,488,495	4%
Netherlands	22,742,314	5.5% (4%)

Values are based on the authors' own calculations.

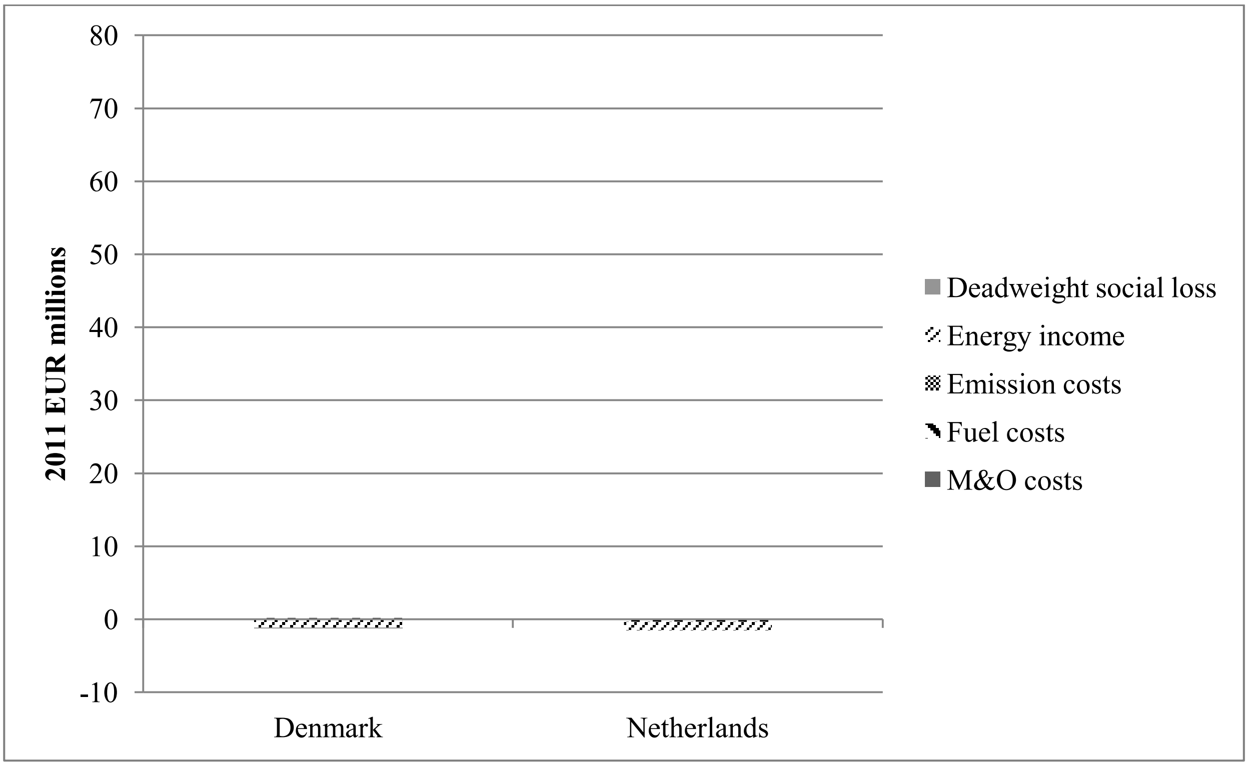
For both Denmark and the Netherlands, the NPV is clearly positive, with approx. 66.5 million Euros and approx. 22.7 million Euros for each case, respectively. These are net benefits of the biomass CHP over the natural gas engine CHP. For both cases one would therefore ignore the alternate investment in favour of the proposed installation.

Significance of the methane emissions

A closer look at the net benefit calculations shows that the largest benefit is captured from the reduction in methane emissions from the switch from the natural gas engine CHP. Methane emissions are weighted heavily in both countries as part of the combined greenhouse gas emissions, with 1 kg of CH_4 being equal to 25 kgs of CO_2 (Danish Energy Agency, 2013a). Methane emissions from the natural gas engine CHP system are particularly high, with approx. 9.6 tons of methane emitted annually for the system estimated in this paper.

In Figure 1.4, the present values (PVs) of five categories of costs and benefits are illustrated. Emission costs clearly dominate the present value calculations.

Figure 1.4 PV breakdown across five categories for the biomass CHP scenario minus the natural gas engine CHP scenario



Values based on authors' own calculations. Changes are shown as a negative or positive numbers, where positive numbers are an annual net benefit and negative numbers an annual net cost when the biomass CHP is installed instead of a natural gas CHP.

Of the five categories included in Figure 1.4, the emission costs is the most visible with the loss in energy income from reduced sales of electricity to the grid discernible as negative values. The remaining three categories of deadweight social loss, fuel costs and M&O costs are not easily discernible to the naked eye.

Methane emission costs represent roughly 99% of the total emission costs for both Denmark and the Netherlands. If the methane emissions are excluded from the analysis, i.e. the other greenhouse gases and all other variables kept constant, the NPV calculations change to approx. -0.8 million Euros and approx. -1.5 million Euros for Denmark and the Netherlands, respectively. By excluding methane emissions, the NPV changes from a positive to a negative number, such that the biomass CHP now carries a net cost to society instead of a net benefit.

If instead of a spark ignition engine CHP system the greenhouse owner would choose to invest in a single cycle mini gas turbine CHP system, the difference in annual methane emissions would reduce from 9.6 tons to 9.7 kgs. By modifying the rest of the technology-specific assumptions accordingly with data from the Danish Energy Agency (2012a), the resulting NPV calculations are given in Table 1.5.

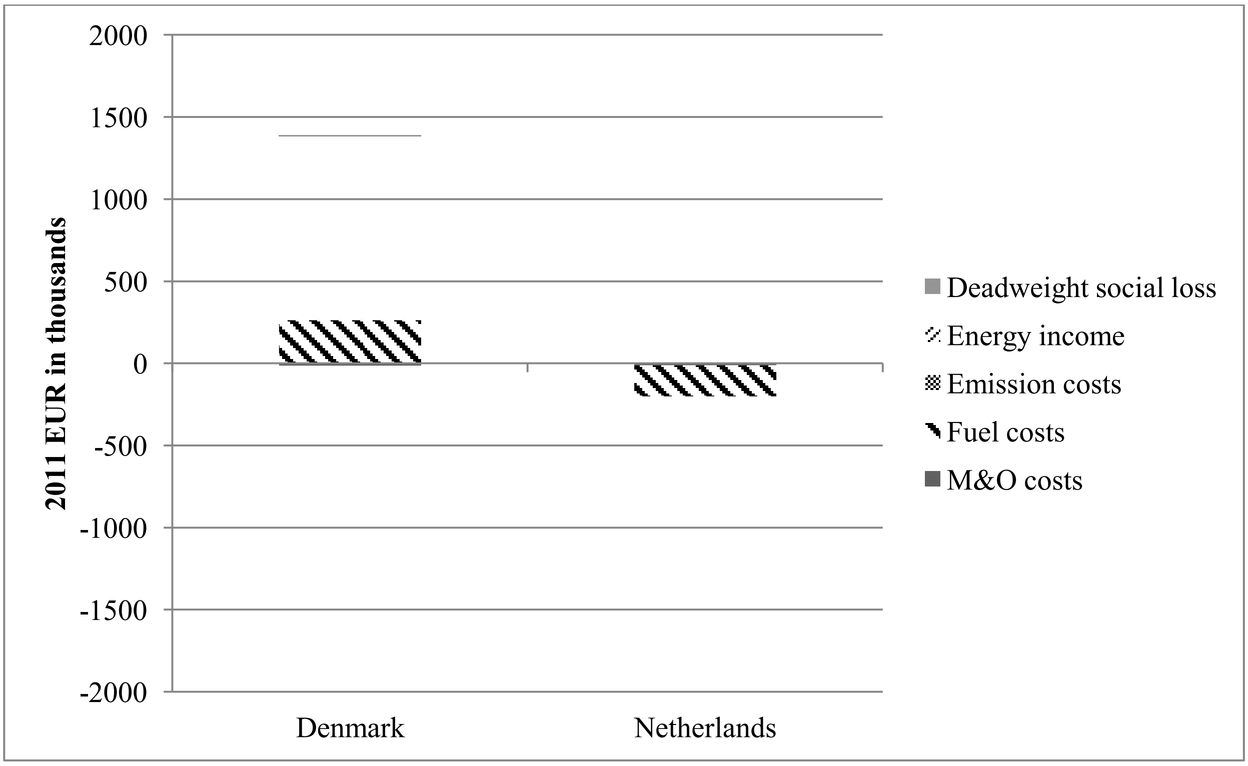
Table 1.5 Net present values for the biomass CHP system minus the natural gas turbine system

2011-EUR	NPV	Discount rate
Denmark	173,502	4%
Netherlands	-1,098,325	5.5 %

Values are based on the authors' own calculations.

The use of a different natural gas CHP technology in the alternate scenario provides more reasonable NPVs relative to the initial capital investment cost. For Denmark, the biomass CHP technology still presents a net benefit to society relative to the natural gas turbine CHP with a positive NPV of approx. 0.2 million Euros. However, the Dutch case now results in a negative NPV, signifying that the biomass CHP confers a net cost to society relative to the alternate natural gas CHP technology. The breakdown of the NPV into PVs across five categories is shown in Figure 1.5.

Figure 1.5 Breakdown of the NPV for the Danish and Dutch cases across five categories



Values are based on the authors' own calculations

The difference in the PV of the M&O costs in both countries and the deadweight social loss for Denmark are marginal, and therefore difficult to see in the figure. Negative PVs are predominantly due to the loss in energy income from the reduced sale of electricity to the grid, while benefits primarily result from the reduced emissions of the gases considered. Fuel costs are counted as a net benefit in Denmark, as annual fuel costs for the woodchip CHP system are lower than for natural gas, while the reverse is true for the Netherlands.

The loss in electricity income is similar for the Netherlands and for Denmark. We would have expected that the energy income loss for the Dutch case would have been greater, as Dutch electricity prices rose sharply over the period in contrast to Danish prices. With a common EU market for electricity, we would not expect such great – and increasing – disparity in electricity price estimates. These differences do not influence the final NPV calculation much as what is captured there is the difference in energy income generated by the biomass and natural gas CHP systems; although the prices themselves are higher, the scale is not significant enough to engender large variations between the two countries.

Deadweight social loss has a minor impact in Denmark and for both alternative natural gas systems in this case study. This is partly due to the scale of the proposed projects, and it is not inconceivable that a large-scale investment, e.g. an offshore windmill park financed primarily through electricity subsidies, will have a much higher deadweight social cost.

Net present values relative to subsidy levels

Table 1.6 shows the NPV of the estimated subsidy for the reference energy plant, the biomass CHP, minus the NPV estimates of the reference and the two alternate energy plants, the natural gas engine and turbine CHPs. There are two subsidy estimates for Denmark, as the subsidy is based on the investment difference between the reference and each of the alternate scenarios. For the Netherlands, the estimated subsidy is based on 12 years of additional income gained based on the Phase 1 value in the SDE+ policy support program.

Table 1.6 Cost benefit and subsidy NPVs for Denmark and the Netherlands

2011 € for base year 2014	Denmark[1]		Netherlands[2]	
	Turbine	Engine	Turbine	Engine
NPV subsidy	74,519	247,596	1,273,684	
NPV investment	173,502	66,488,495	-1,098,325	22,742,314

[1]Calculated at a discount rate of 4% unless otherwise indicated. [2]Discount rate of 5.5% unless otherwise indicated.

The Danish subsidy levels are significantly lower than the Dutch ones for the same technology and change in line with the reduction in NPV from one comparison to the other. This is one of the advantages of the capital investment subsidy relative to an annual compensation in the form of a feed-in tariff or premium. The magnitude of the Dutch subsidy does not change regardless of whether the estimated NPV is positive or negative, depending on the alternate energy plant.

1.1 Sensitivity analysis and discussion

The sensitivity analysis will be broken down into five segments, shown in Table 1.7. Given the dominance of methane emission values for the natural gas engine CHP system, the sensitivity analysis is conducted using the natural gas turbine CHP system as the reference.

Table 1.7 Changes to the NPV from sensitivity analysis

2011 € for base year 2014	Denmark[1]		Netherlands[2]	
Original NPV	179,000		-1,098,000	
+/- 25% Investment + M&O for biomass CHP	-56,000	414,000	-1,328,000	-869,000
+/- 25% Woodchip fuel cost	-339,000	697,000	-1,705,000	-491,000
+/- 25% Natural gas fuel cost	763,000	-405,000	-539,000	-1,658,000
+/- 25% Greenhouse gas emission cost	481,000	-123,000	-989,000	-1,207,000
+/- 25% Electricity costs	-110,000	468,000	-1,404,000	-793,000
NPV at a 3.5% discount rate	193,000		-1,234,000	

All values rounded to nearest thousand. [1]Calculated at a discount rate of 4% unless otherwise indicated. [2]Discount rate of 5.5% unless otherwise indicated.

The Dutch NPVs are resolutely negative throughout all variations in the sensitivity analysis, whereas the Danish NPVs are balanced equally between negative and positive depending on the direction of the change. In contrast, the comparison with the initial natural gas CHP technology is overwhelmingly positive throughout the sensitivity analysis. The use of a common 3.5% discount rate instead of 4% or 5.5% shows little impact on the states' NPVs.

The NPVs show the most variation to sensitivity analysis of the two fuel prices. This is especially noteworthy given that fuel costs are only the third largest segment impacting the NPVs illustrated in Figure 1.5, following energy income and emission costs.

Divergence in CBA methodology runs the risk of producing results which do not maximize welfare gains. Differences in CBA results for the same case study in two states indicate divergence in methodology or a natural variance between the two states, or a combination of both. The results above demonstrate that the Danish CBA results are significantly more positive than the Dutch results, most likely due to a combination of differences in methodology and natural properties.

The main methodological differences are the choice of baseline for comparison, the discount rate, treatment of distributional weights and social deadweight loss, among others (Meeus et al., 2013). The estimation of socioeconomic weights might also come under this heading, although it might be equally justified to include it as part of the natural variation between states or even regions. Natural variation includes data consistency and quality for instance for fuel costs, electricity prices, land and labour etc.

In this paper, much of the disparity between the results can be attributed to the difference in fuel costs – the difference between Danish woodchip and natural gas prices is smaller than the Dutch, meaning the fuel cost increase from switching to woodchip is more moderate than in the Netherlands. These differences are pervasive enough that the net fuel costs are included as a benefit in the Danish case, i.e. the switch from natural gas CHP to biomass CHP results in annual fuel cost savings, while net fuel costs in the Dutch case impose an additional annual cost on the greenhouse owner. These differences are impacted by the switch from a larger natural gas CHP system to a smaller biomass CHP system, where the latter generates less electricity output but also requires less energy input.

Emission valuations, on the other hand, are significantly different for both countries, and while some disparity should be expected, the extent of this disparity is so great that it dominates the estimation of net public benefits, particularly for the engine-based scenario. Considering that the two member states were chosen for their similarities, we did not expect to observe such great differences in the valuation of emissions, particularly with respect to CO2 emissions. It is likely that the differences result from the method used to place a monetary value on non-monetary externalities, as natural differences are unlikely to account for the significant variation in CO2 valuations shown in Table 1.1.

In terms of greenhouse gas emissions, which do not pay heed to state borders, an argument could be made for setting a value uniform throughout the member states, or at the very least ensuring that all member states follow the same methods for assigning values.

1.5 Conclusion and policy implications

The purpose of this paper was to examine sources of discrepancies in CBA methodology and estimate their impact on results, in order to determine whether divergent approaches influence the calculation of welfare gains. This is most clear in the choice of the baseline for the analysis. For the Danish case, the resulting NPV is positive regardless of whether the biomass CHP is compared with the engine or turbine alternative, but for the Dutch case there is only a positive NPV for the engine alternative. This has at least two implications for policy design. First, if subsidies for renewable electricity are awarded irrespective of what fossil-fuelled alternative they crowd out, then policymakers run the risk of rewarding projects which promote net social loss. Second, the results are very sensitive to the choice of baseline technology. In this paper, it was assumed that the choice of a natural gas system was simply a replacement for an existing unit, with two possible units included to demonstrate sensitivity. In the real world, the project manager may be choosing from a larger set of possible alternatives. It is possible that the choice of the baseline or even multiple baselines will be deliberately selected in order to demonstrate the desired NPV outcome.

Limitations of the paper include not taking into account the potential benefits from industry and business growth in new areas, and security of energy supply by diversifying energy feedstock. We recommend that further research in the formulation of CBA methodology for a common EU policy framework includes case studies to demonstrate the extent of sensitivity both due to natural variations between states and to discrepancies in the approach used.

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Chapter 2. Understanding the implicit bias in ranking dissimilar capital investments

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2.1 Abstract

A review of the literature on capital investment comparisons from both welfare economics and corporate finance shows little or no agreement on the correct approach to comparing dissimilar investments, i.e. investments with different lifetimes, different investment magnitudes and implicit reinvestment assumptions. This lack of agreement carries over to practitioner guidelines published by international authorities such as the EU and OECD. This paper refers back to Mishan (1973) to show that a simple test can reveal the existence of implicit bias when ranking dissimilar capital investments. The paper compares five dissimilar energy investments in a case study for Denmark to demonstrate the rankings made by following guidelines and the extent to which benefits and costs may be over- and understated. Following conventional guidelines clearly yields contradictory results. The choice of measure can reveal insight into the decision-makers preferences and objectives when choosing between capital investment options.

2.2 Introduction

Why do similar capital investment measures provide conflicting rankings in comparison analyses? One answer, provided by Mishan (1973), showed that three different time-weighted investment measures will provide the same rankings when:

- Capital investments have the same lifetimes
- Capital investments have the same initial investment
- Reinvestment assumptions are explicitly accounted for

When these three conditions are met, the capital investment measures' net present value (NPV), internal rate of return (IRR) and profitability index (PI) will give you the same ranking. However, if capital investments are compared directly where even one of these conditions is violated, the rankings will be biased and the three measures will no longer rank consistently. The direction and magnitude of the bias is partly determined by the investment measure used and evidence from the applied field suggests that this bias can have profound impact on the ranking order (Kelleher & MacCormack, 2005).

Neither corporate finance nor welfare economics literature provides clear and comprehensive guidance when comparing dissimilar investments in order to control for unwanted bias in the event of inconsistent rankings, although both these fields use NPV and IRR measures to evaluate options. This lack of guidance in academic literature carries through to the guidelines published for practitioners, providing misleading and sometimes contradictory advice.

Surveys of private-sector decision-makers reveal that these measures are widely used, and practitioner guidelines published by the OECD (2006) and the EU (2008) imply that they are equally popular among non-private sector decision-makers. The lack of clarity surrounding the use of these measures for comparing dissimilar options therefore has profound implications for the selection and ranking of most capital investments today.

This is particularly true for decisions regarding energy infrastructure, given that the more similar investment alternatives are, the more likely that the rankings will be unbiased across the measures. Unfortunately, energy investment alternatives are rarely similar with respect to lifetimes or investment magnitudes, especially where the comparison includes fossil-fuelled and renewably-fuelled technologies. This means that the likelihood of a biased ranking when comparing dissimilar energy alternatives is very high, which is worrying given that the decision-maker may not even be aware of the existence of this bias.

The overarching aim of this paper is to demonstrate that the choice of measure used for ranking dissimilar options will strongly influence the order of the ranking. Using three common measures to rank options provides a simple test to determine whether or not the rankings are biased. A summary of private-sector surveys detailing the prevalence of the three mentioned capital investment measures and a synthesis of existing capital investment comparison guidelines from leading texts in both corporate finance and welfare economics is provided. Finally, five energy investment options are ranked using these measures in an attempt to determine which single option and which combination of options are the most profitable.

This paper is organized as follows: the following section presents the literature review, which includes results from survey evidence of the popularity of key capital investment measures and a review of the literature available on capital investment comparisons. This is followed by a more detailed presentation of Mishans (1973) proposition. The inherent limitation of each of the chosen capital investment measures is briefly illustrated in a stylized comparison of five energy options with similar annual power output but otherwise differing characteristics. The paper concludes with a brief discussion on the direction of bias of each measure and possible avenues of further research.

2.3 Literature review

This section provides a thorough review of four types of literature available on capital investment comparison theory: cross-sectional surveys of private-sector decision-makers; leading textbooks from both corporate finance and welfare economics; ranking disputes in article-based literature; and finally, the recommendations from practitioner guidelines. The purpose is to illustrate how the guidelines to correct usage of the most popular capital investment comparison measures are confusing, misleading and, in some cases, incorrect.

While the NPV and IRR measures have been subject to intense debate over the last six decades (Alchian, 1955), very little has been done to distil key recommendations and disseminate them to the practitioners who use them on a daily basis. The result of this is that neither key textbook material nor officially sanctioned guidelines are sufficient to inform practitioners of correct application of their favourite measures or the consequences of incorrect usage.

Brief review of the three common capital investment measures

Net present value

As an investment evaluation measure, the NPV presents the decision-maker with an immediate answer to whether a capital investment will earn a return that at least matches the opportunity cost of not investing in the alternative. The net cash flow of the investment over its lifetime is summarized into a single figure and discounted by a chosen discount rate. In corporate finance literature, the discount rate is often set to the weighted average cost of capital (WACC), the minimum accepted rate of return (MARR) or the risk-free interest rate, while in welfare economics the rate of choice is the social rate of time preference (SRTP). In this paper, we assume that the discount rate reflects the opportunity cost of the investment, i.e. it represents foregone earnings from an alternative investment.

Solving for NPV, such that an investment made at time t=0 (I_0) is subtracted from the sum of the future net benefits (*NB*) over an investment's lifetime (*t=0,…,n*), each of which is weighted by the discount rate (*r*) at time *t=n*;

$$NPV = -I_0 + \frac{NB_1}{(1+r)^1} + \frac{NB_2}{(1+r)^2} + \ldots + \frac{NB_n}{(1+r)^n} = -I_0 + \sum_{t=1}^{n} \frac{NB_t}{(1+r)^t}$$

The NPV is expressed in a given currency and is stated in absolute terms. The discount rate is expressed as a constant percentage. The accept/reject decision for an option requires a positive NPV, i.e. an NPV value greater than zero.

From the decision-makers perspective, a positive NPV simply signifies that the investment earns more than the minimum required, while a negative NPV indicates the opposite. The decision to accept or reject an investment therefore hinges on whether the NPV is a positive or negative number.

Internal rate of return

The IRR, similarly to the NPV, is a function of the amounts of cash flows and their timing over the investment lifetime. The IRR is expressed as a percentage and is an intuitively obvious measure of the benefits of a given option relative to its initial outlay. The accept/reject decision of a given investment must be compared to a hurdle rate, typically the WACC, MARR or SRTP mentioned above. If a given investment proposal results in an IRR greater than the hurdle rate, the option is usually undertaken. Unlike the NPV, the IRR cannot differentiate between an initial outlay followed by a stream of positive returns and an initial income followed by a stream of payments. It is up to the user to ensure that the NPV and IRR are compatible.

Solving for the IRR, *r*, such that an investment (*I*) made in the current time period (*t=0*) is equal to the sum of future net benefits (NB) over the lifetime of the investment:

$$I_0 = \frac{NB_1}{(1+r)^1} + \frac{NB_2}{(1+r)^2} + \ldots + \frac{NB_n}{(1+r)^n} = \sum_{t=1}^{n} \frac{NB_t}{(1+r)^t}$$

The IRR is expressed as a percentage and measures the benefits of a given investment relative to its initial outlay (or the costs relative to an initial payout). The accept/reject decision of a given investment must be compared to the identified hurdle rate. If a given investment proposal results in an IRR greater than the hurdle rate, the proposal is judged profitable.

The two measures, NPV and IRR, are tied together in the sense that for an NPV = 0, the IRR will be equal to the selected discount rate. Thus the IRR of an investment is often referred to as the discount rate for which the NPV would be zero.

Profitability index

The PI is the present value of future income over the initial investment, in other words, the value of the discounted net benefits of an investment relative to the original outlay. In this paper, the PI is interchangeable with the present value index and the benefit-cost ratio. The decision to accept/reject an investment depends on whether the PI exceeds the value one. An investment with a PI of less than one is judged unprofitable, similar to when the NPV is less than zero or the IRR is less than the chosen hurdle rate.

Solving for PI, the present value of the sum of future net benefits of the investment (PV), not including the initial investment, is divided by the initial investment (I_0) made in the current time period ($t=0$):

$$PI = \frac{PV}{I_0}, \text{alternatively } PI = 1 + \frac{NPV}{I_0}$$

The NPV is the net present value of the investment, as introduced above. The PI is a ratio, and the decision to accept/reject an investment depends on whether the PI exceeds the value one.

Survey evidence on the measures of choice

The majority of decision-makers use one of two capital investment measures to evaluate potential returns, the NPV or the IRR. Without a thorough understanding of how violations of any of the three previously stated conditions will affect their chosen measure, decisions based on the resultant rankings will be compromised.

Table 2.1 provides the proportion of decision-makers favouring the NPV, IRR and the PI (or its equivalent), summarized from surveys on capital budgeting practices from the literature. As noted by the review published by Burns & Walker (2009), the number of surveys of capital budgeting practices for the US has decreased dramatically over time. In Table 2.1, only one survey is included for the period 2000-2008, which was conducted for European firms. The sole survey of the US for the same period sought to determine the extent of adoption of real options analysis and is not included in Table 2.1.

Table 2.1 Surveys of capital budgeting practices

Author	Share (%) using			N firms	Response rate (%)	Region
	NPV	IRR	PI			
Gitman & Forrester[1] (1977)	9.8	53.6	2.7	112	38.4	US
Sangster (1993)	48	58	n/r	94	21.8	Scotland
Remer et al. (1993)	52 97	100 90	n/r n/r	27 33	n/r 20	US
Block (1997)	11.2	16.4	n/r	232	27.3	Small firms, US
Farragher et al. (1999)	78	80	n/r	379	34	US
Graham & Harvey[2] (2001)	74.9	75.7	11.9	392	9	US
Ryan & Ryan[3] (2002)	85.1	76.7	21.4	205	20.5	US
Brounen et al.[4] (2004)	35-70	42-56	8-38	52-132 Total N=313	5	UK, Germany, Netherlands and France

*n/r = not recorded; [1]Only primary technique included; [2]Always or almost always; [3]Always or often; [4]Presented as a range across countries

The NPV and the IRR were the most popular capital investment measures employed by private decision-makers in large firms by the 1990s. Since no recent surveys have been carried out, it is difficult to determine whether their popularity is still as prevalent today. The study published by Brounen et al. (2004) seems to indicate that the measures are slightly less popular in the four European countries surveyed, although the range of answers indicates significant variation from country to country.

Smaller firms, as evidenced by the survey published in 1995, seem less inclined to favour NPV and IRR, possibly because they are less likely to favour any time-weighted investment measure due to its apparent complexity.

The PI measure was not generally included in the survey questions until the late 1990s (here with the exception of the Gitman & Forrester survey from 1976), possibly indicating its lack of prevalence in capital investment decisions.

The NPV and IRR measures in the literature

The recommendation from the corporate literature reviewed in this paper (Brealey & Myers, 1999; Brealey & Myers, 2003; Damodaran, 2011) is that the IRR should not be used directly or at all for investment rankings. The use of the IRR is inadvisable due to its implicit reinvestment assumption, which is its treatment of the intermediate cash flow during the investment lifetime. The IRR assumes that the intermediate cash flow, i.e. the net annual return, is reinvested at the IRR for as many years as is left of the investment. Where the reinvestment rate is not explicitly accounted for, the IRR of a single investment can overstate or understate the perceived returns of the investment.

As was noted in the introduction, Mishan (1973) suggests that if reinvestment assumptions were not made explicit, options could not be directly compared against one another, even when the investment lifetimes and initial outlay magnitudes were equal. He also states that using the NPV method of ranking when investments have unequal initial outlays implicitly assumes that the smaller investment outlays are fixed; i.e. the difference between the larger outlays and the smaller outlays is not invested.

The Green Book (2003) recommends using the NPV method as the decision criterion, i.e. the decision to accept or reject an investment, in the context of full cost-benefit analyses. It directly warns against using the IRR as the decision criterion for accepting/rejecting an investment, although it adds that the IRR can be used to rank proposals. It notes that the IRR may provide different/incorrect answers relative to the NPV, though without clarifying when and why this might occur. The EU Guide (2008) also recommends using the NPV as the decision criterion, but expects that the “examiner” (decision-maker) will use the IRR to compare the future performance of the investment relative to other options, especially when the options are similar except w.r.t. size. The OECD Guide (2006) states that the correct approach is to rank options by their NPVs and adopt all investments with a positive NPV when there are no budget constraints.

It should be noted that one of the reasons why the use of the NPV is recommended relative to the IRR is the belief that while the IRR may have multiple solutions if the net annual returns experience a sign change, the NPV measure remains unaffected. In other words, if one of the net annual returns was a negative number, for instance due to additional investment outlays during the investment lifetime, there could be two IRR values – one for each of the investment outlays. Studies by Oehmke (2000) and Joaquin (2001) demonstrate that the same sign change would also affect the NPV values in certain circumstances, so this argument for the apparent superiority of the NPV should be used with caution.

The PI measure in the literature

For the decision-maker working under a single-period budget constraint, Brealey & Myers (1999) recommend that the PI is used to rank options, and that all the options with the largest PIs are selected until the budget is exhausted. In an alternative edition from (2003) they include the corollary that if other constraints exist at the same time as a single-period budget constraint, e.g. mutual exclusivity, the PI approach fails. In this case, they suggest using more advanced methods, such as linear programming.

Damodaran (2011) states that the scale issue from use of the NPV measure is counteracted by using the PI measure instead. He also notes that the limitations of the PI include that it cannot take budget restrictions in future periods into account, and it does not necessarily maximize total investment returns for a given budget where the initial investment is lower than the budget maximum. Even under the single-period budget constraint it should be used with care, as it does not present the best combination of options available within a budget, but only ranks investments individually.

The OECD Guide (2006), the only of the three CBA guides to refer to a case with a single-period budget constraint, states that since the public sector always faces budget restrictions, one should always use the B/C ratio (~PI) to rank options. It goes on to state that this method cannot be used if, in addition to the single-period budget constraint, the investments are also mutually exclusive, in which case the appropriate decision rule is to choose the option with the largest NPV and an outlay that does not exceed the budget constraint.

Mishan (1973) states that ranking by the PI implies that any of the investments can be replicated as many times as necessary. In other words when comparing an option which exhausts the available budget to an option which only requires one tenth of it, the PI measure will compare the absolute value of the larger investment with the absolute value of ten of the smaller investments; whichever returns the larger value will be ranked highest. However, even in the unlikely event that the smaller option could be replicated until both initial investment outlays were equal, in any mutually exclusive scenario you would only want one in the investment lifetime.

Modified internal rate of return

A final, less known measure included in this paper is the modified internal rate of return (MIRR). This measure has been deliberately constructed to overcome some of the know issues of the IRR, as demonstrated in the following sections.

Solving for MIRR, such that *n* is the number of cash flows, r^R is the reinvestment rate for positive values, *B*, and r^F is the finance rate for negative values, *C*, over an investment's lifetime (*t=0,…,n*);

$$MIRR = \left(\frac{-NPV(r^R, B_t) * (1 + r^R)^n}{NPV(r^F, C_t) * (1 + r^F)}\right)^{\frac{1}{n-1}} - 1$$

Mishan's proposition

Mishan (1973) was possibly the first to point out that if investments are similar, direct comparisons will provide consistent rankings across all three measures. His definition of similarity takes into account the following three criteria:

- Equal investment lifetimes
- Equal initial investment outlay magnitudes
- Explicit reinvestment assumptions

When all three criteria are met, the three measures NPV, IRR and PI will provide consistent rankings. This suggests that when the three measures provide different rankings in an investment comparison under reasonable assumptions, one or more of the comparison criteria have been violated and ranking direct comparisons across options is not possible.

The natural extension of this is to use the three measures as a test for bias in the rankings. If they provide consistent rankings bias will be limited, whereas inconsistent rankings suggest further analyses should be undertaken to achieve reliable rankings across dissimilar investments.

Where the test shows consistency, the decision-maker is still able to rely on her measure of choice – a thorough understanding of all three measures is therefore not required to ensure correct investment comparisons.

2.4 Numerical example

Assume you are a decision-maker requiring a new energy system at a site in Denmark. You have narrowed down potential investments to five technically feasible choices; two power-only systems based on renewable fuels and three combined heat and power (CHP) systems, one of which is based on a renewable fuel and the others which are based on conventional fuels. For the purpose of this decision, installation, grid connection costs, permits, income tax and land use are comparable and do not affect the final decision. The energy systems are sized according to an expected annual power demand of roughly 495 kWh.

You wish to determine whether the best decision would be to choose one of the five options or a combination of a power-only investment with a CHP investment. A new support scheme to promote investments into renewable energy technologies is available for the three renewable energy-based options, an upfront capital subsidy valid for investment costs exceeding a conventional energy alternative, up to a maximum of 65% of the whole investment cost for small industries or DKK 23 per GJ fossil fuel replaced over a 10-year period (Danish Energy Agency, 2013).

Basic investment characteristics of the five options are provided in Table 2.2. With the exception of the discount rate, the remaining characteristics are taken from the Danish Energy Agency publication *Technology Data for Energy Plants* (2012a).

Table 2.2 General characteristics of investment options

Technology type	Lifetime (years)**	Initial investment (EUR)	Discount rate (%)	Net power capacity (kWe)	Equivalent full-load operating hours	Annual M&O (EUR)
Photovoltaic (PV) electricity*	30	930,000	4	620	800	16,864
Wind electricity	15	363,000	4	330	1,500	6,930
Woodchip CHP	15	350,000	4	65	7,621	15,120
Natural gas spark engine CHP	20	90,000	2	60	8,322	5,493
Natural gas turbine CHP	10	126,000	2	60	8,322	4,494

*The inverter needs to be replaced every 10 years; it is assumed that the cost of doing so is roughly 10% of the initial capital outlay (Danish Energy Agency, 2012a). **Lifetime taken as lower estimate where a range of estimates are given. Sources: Danish Energy Agency 2012a, Danish Ministry of Finance 2013

The discount rates considered in this paper are those recommended by the Danish Ministry of Finance (2013) and consist of a risk-free rate of 2% and a risk premium of 2%. As renewable energy technologies are widely regarded as more uncertain investments, this paper uses the 4% rate for renewable energy options and the 2% rate for the conventional energy options. Damodaran (2011) rightly points out that options which are riskier, for instance in the case of new and untried technology, may require higher hurdle rates than their less risky alternatives. An alternate method of dealing with additional risk is to adjust the net annual returns of a specific investment accordingly.

All prices are reported in real Euro prices, at the 2011 price level. The exchange rate between the Danish Krone (DKK) and the Euro is set at DKK 7.5 per Euro. The Danish Krone is fixed at 7.46 against the Euro, but there are costs involved in exchanging, so the exchange rate is rounded upwards (European Central Bank, 2013).

It is assumed that the decision-maker is indifferent between the differing physical characteristics and space requirements of the investments. Income and costs are affected by national characteristics, including fuel prices and renewable energy subsidies. Inflation and taxes are disregarded for simplicity. Costs of fuel and values for power and heat are taken from the Danish Energy Agency's guidelines for socioeconomic calculations (Danish Energy Agency, 2012b).

Using the data shown in Table 2.2, the returns using the three standard measures for each option are presented in Table 2.3.

Table 2.3 Capital investment comparison using NPV, IRR and PI

Technology type	NPV (EUR)	IRR (%)	PI	MIRR* (%)	Hurdle rate (%)
PV electricity	- 54,063	3.0	0.94	2.3	4
Wind electricity	187,614	16.3	1.52	5.6	4
Woodchip CHP	57,964	9.0	1.17	3.9	4
Natural gas spark engine CHP	100,198	11.5	2.11	5.9	2
Natural gas turbine CHP	- 48,780	- 7.0	0.61	-2.9	2

Discount rate equal to 2% or 4%, the former for conventional fuel options. Underlined values represent the highest ranked option. *Finance rate set at 4% for renewable energy options and 2% for conventional energy options. Reinvestment rate set at 2% across all options. The highest rank option is underlined.

As is seen in Table 2.3, the NPV and IRR measures rank the wind electricity system highest, while the PI measure ranks the natural gas spark engine CHP highest. The natural gas turbine CHP and PV electricity systems are non-viable options according to all measures. If there were no budget constraints and the options were not mutually exclusive, the optimal decision would be to invest in the remaining three viable options.

As noted in the preceding section, inconsistent results suggest that underlying bias affects the perceived rankings across the three measures. As demonstrated in Table 2.2, initial outlays and technical lifetimes are significantly different and the options cannot be said to be similar, despite being sized for similar annual power outputs.

Explicit reinvestment rate assumption

For the NPV calculations and by extension the PI calculations, the chosen discount rates of 2% and 4% reflect the overall profitability requirement (an NPV of zero would indicate that the investment has earned a 2% or 4% return, respectively, over its lifetime), the cost of borrowing and the return on intermediate cash flow returns. In other words, if there were a year where the annual income did not cover the cost of e.g. a replacement inverter for the PV electricity system, the replacement cost would be borrowed at a rate of 4% interest. Similarly, any year where there is a positive net income, this intermediate income would be invested at the relevant discount rate for the duration of the option lifetime.

In contrast, the chosen discount rate has no bearing on the IRR calculations. The IRR generates its own, implicit, reinvestment rate (multiple rates where the net annual income is not always positive) and applies it to any intermediate income for the duration of the investment lifetime. This implicit reinvestment rate can be markedly different from the discount rate used in the NPV and PI calculations; for the options in Table 2.3, the IRR ranges from -7% to 16.3% across the five options.

This implies that the intermediate net cash flows for each year for the natural gas turbine CHP option are reinvested with an expected return of -7% for the remainder of the investment lifetime, whereas the intermediate net cash flows for the wind electricity option are reinvested with an expected return of 16.3%.

If the decision-maker has access to investments with a return of 16.3%, then an expected reinvestment rate of 4% (the selected hurdle rate/discount rate for the wind electricity option) is excessively low. Typically, the hurdle rate reflects the expected return that could be earned elsewhere. By replacing IRR with the MIRR, the risk-free discount rate of 2% can be imposed on the IRR calculation.

Note that not only has the IRR measure significantly decreased for the wind electricity option, the ranking of the options has also changed, with the natural gas spark engine CHP now being ranked the highest. The MIRR rankings are now in line with the PI rankings from Table 2.3, but there is still a discrepancy when compared with the NPV rankings. The rankings therefore still contain unresolved bias after making the reinvestment assumptions explicit.

Equal investment lifetimes

In the corporate finance literature reviewed, two methods are recommended to correct for different investment lifetimes. These methods are the replication method (Damodaran, 2011) and the equivalent annuities method (Brealey & Myers, 1999 and 2003; Damodaran, 2011).

Given estimated lifetimes ranging from 10 to 30 years, the replication method requires extending the total lifetime to 60 years to achieve multiples of each investment lifetime. As such, the longest lived option was replicated twice while the option with the shortest lifetime was replicated 6 times.

The equivalent annuities method simply requires modifying the NPV with a discount factor adjusted for the option lifetime. For each option, the NPV is normalized to an annual value by dividing by a modified discount rate which takes into account its lifetime.

Table 2.4 gives the NPV estimates for the five investments with normalized investment lifetimes.

Table 2.4 Capital investment comparison with normalized investment lifetimes

Option	**Replication method NPV* (EUR)**	**Equivalent annuities method NPV (EUR)**
PV electricity	- 162,947	- 3,126
Wind electricity	288,867	<u>16,874</u>
Woodchip CHP	- 65,436	5,213
Natural gas spark engine CHP	<u>384,272</u>	6,128
Natural gas turbine CHP	- 39,393	- 5,430

*Discount rate equal to 2% for conventional energy options and 4% for renewable energy options.

The highest ranked option is underlined.

The two methods for normalizing investment lifetimes produce dramatically different rankings; not only are the top-two ranked options different in each calculation, none of the options have the same rank across the two methods. Neither method produces NPV rankings consistent with the MIRR, IRR or PI rankings calculated in Table 2.3.

Note that we would still expect underlying biases due to the untreated difference of unequal initial investment outlays.

Equal investment magnitudes

Out of the reviewed textbooks and practitioner guidelines, none of them agree on the correct approach to comparisons across investments with unequal investment magnitudes. In fact, they provide completely contradictory advice: Damodaran (2011) states you should never use NPV and recommends using a modified IRR and PI while Brealey & Myers (1999/2003) recommend using incremental analysis combined with IRR, which the OECD Guide (2006) supports, although they recommend using NPV in the case of multiple options; finally, Mishan & Quah (2007) recommend ignoring all these and using terminal value to normalize investment scale.

This decided lack of agreement within even the subsets of the literature can only lead to confusion for the decision-maker who needs to compare two or more mutually exclusive investment options, or combine two or more options from a set with mutually exclusive alternatives. That even the practitioner guidelines developed by the OECD and the EU disagree on the approach needed for a comparison between investments of unequal magnitudes suggests that there is a severe lack of guidance in the existing literature.

This section will focus on using the incremental approach, calculating all measures across all pair-wise combinations of options, as well as paired investments against the other paired investments.

The incremental approach

The incremental approach simply requires subtracting the smaller investment stream from the larger investment stream. If the resulting investment stream has acceptable returns on the measures, such as a positive NPV or an IRR higher than the hurdle rate, the larger investment stream is preferable to the smaller investment stream. This holds as long as your hurdle rate is an accurate reflection of your foregone earnings if you had invested the incremental amount elsewhere. For this calculation, we assume that the risk-free discount rate of 2% is the baseline.

Table 2.5 shows the NPV, MIRR and PI for each incremental investment stream. Note that while the reinvestment rate is accounted for in the MIRR, we do not normalize the investment lifetimes.

Table 2.5 Incremental analysis of the five options, in pairwise combinations

Pairwise combination	NPV* (EUR)	IRR** (%)	MIRR*** (%)	PI
PV electricity / Woodchip CHP	- 190,300	-0.6	1.5	0.7
PV electricity / Wind electricity	- 393,400	-5.6	0.3	0.3
PV electricity / Natural gas turbine CHP	- 71,300	2.4	2.2	0.9
PV electricity / Natural gas spark engine CHP	- 157,500	0.5	1.8	0.8
Woodchip CHP / Wind electricity	- 203,000	<u>106.3</u>	-7.1	-14.6
Woodchip CHP / Natural gas turbine CHP	119,000	23.9	3.7	1.5
Woodchip CHP / Natural gas spark engine CHP	32,800	9.4	2.6	1.1
Wind electricity/ Natural gas turbine CHP	<u>322,100</u>	33.4	<u>5.5</u>	<u>2.4</u>
Wind electricity / Natural gas spark engine CHP	235,900	21.8	4.6	1.9
Natural gas turbine CHP / Natural gas spark engine CHP	- 98,500	missing	-100	-1.7

*Discount rate set at 4% for all pairwise combinations including a renewably fuelled option and at 2% for the comparison between the two conventionally fuelled options.

**Hurdle rate set at 4% for all pairwise combinations including a renewably fuelled option and 2% in the comparison between the two conventionally fuelled options.

*** Reinvestment rate set at 2% for all options. Finance rate set at 4% for all pairwise combinations including a renewably fuelled option and 2% in the comparison between the two conventionally fuelled options.

The highest ranked option is underlined. NPV estimates are rounded to the nearest hundred.

The options requiring the largest initial outlay are ordered first in the table, such that the PV electricity option, which has the highest initial capital requirements, is compared to successively smaller options. This continues down the line until the two options with the smallest initial outlays are compared to one another. Refer to Table 2.2 for an overview of the different initial outlays.

Investments which fail to reach an acceptable level, i.e. NPV values of less than zero, IRR and MIRR values lower than the hurdle rate and PI values less than one, indicate that the option with the smaller outlay is more attractive than the compared alternative. For instance, in none of the pairwise calculations featuring the PV electricity option are the measures above the minimum required, suggesting that all of the alternative options are superior to the PV electricity option. The comparison of the two conventional energy options, the natural gas turbine CHP and the natural gas spark engine CHP, provided an incremental investment stream of only negative numbers, which is why the IRR could not be calculated.

The wind electricity option is clearly superior, as when compared with options with larger initial outlays the investment measures fail to reach the minimum required, and when compared with options with smaller initial outlays the measures exceed the minimum. The only exception to note here is the IRR value for the pairwise combination of woodchip CHP and the wind electricity system which is much greater than the hurdle rate of 4%. The reason for this is straightforward; the incremental cash flow consists of an initial positive value followed by a stream of negative values, and the IRR calculation is indifferent to the significance attached to the sign values.

Another point worth noting is that only for the pairwise combinations of wind electricity and the two natural gas systems does the MIRR exceed 4%, the rate chosen as the finance rate and therefore the minimum hurdle rate.

The incremental approach extended to the best combination of options

If we ignore the non-feasible options from Table 2.3, we are left with the wind electricity option, the woodchip CHP option and the natural gas spark engine CHP option. The latter two are baseload technologies, while the first has an intermittent fuel supply and therefore runs for a far smaller amount of hours in a given year. It would therefore make sense to compare combinations of the wind electricity option with each of the CHP options, as the two CHP systems could conceivably be switched off when there is sufficient wind to generate the needed electricity, thereby saving on fuel expenditure and possibly extending the lifetime of the technologies.

Adding the single investment streams of each pairwise combination and then subtracting the smaller combined investment stream (conventional spark engine CHP with the wind electricity option) from the larger investment stream (woodchip CHP with the wind electricity option) gives an investment lifetime of 20 and 15 years, respectively. The incremental investment stream is discounted by 4% for the NPV calculation and a finance rate of 4% and a reinvestment rate of 2% are used in the MIRR calculation. As the smaller investment has a lifetime 5 years longer than the larger investment, the final 5 years of the incremental investment calculation are negative, and the IRR could not be calculated. The remaining three measurements are provided in Table 2.6.

Table 2.6 Incremental comparison of the remaining paired investment options

Combined pair	NPV* (EUR)	MIRR** (%)	PI
Woodchip CHP + Wind / Spark engine CHP + Wind	- 190,302	1.5	0.7

*Discount rate set at 4% for all pairwise combinations including a renewably fuelled option and at 2% for the comparison between the two conventionally fuelled options.

*** Reinvestment rate set at 2% for all options. Finance rate set at 4% for all pairwise combinations including a renewably fuelled option and 2% in the comparison between the two conventionally fuelled options.

None of the measures reach acceptable levels, indicating that the best combination of options is the natural gas spark engine CHP with wind electricity. Interestingly, these two options have consistently ranked first and second in tables 2.3 and 2.4, but in the incremental comparison in Table 2.5 the woodchip CHP is found to be the better investment across all measures except the MIRR, which fails to reach a 4% hurdle rate. This suggests that the woodchip CHP system is a better option than the natural gas spark engine CHP as a stand-alone system, but not when paired with the wind electricity investment.

2.5 Discussion

What does the choice of measure indicate regarding the objectives of the decision-maker? When investments are dissimilar, particularly with respect to initial outlays, lifetime and when there are implicit reinvestment assumptions, the evaluation measures will be biased. The direction and magnitude of the bias will be determined not only by the extent to which the options are dissimilar, but also on which measure is preferred.

Direction of bias

Net present value

When options are similar, with no significant differences in initial outlays or lifetime, the NPV will favour the option that provides the greatest absolute return. When initial outlays differ, the largest option will be favoured, as will the option with the longest stream of net positive returns when lifetimes differ.

This suggests that the investment with the longest lifetime and the largest initial outlay would rank the highest. From the characteristics in Table 2.2, that would be the PV option with an initial investment of € 930,000 and a lifetime of 30 years, but instead the NPV calculation in Table 2.3

ranks the wind option highest, despite an initial investment of € 363,000 and a lifetime of only 15 years. Instead, the wind option is favoured with significantly lower maintenance and operation costs, such that the net annual positive returns are roughly € 10,000 greater.

Part of the reason why the NPV rankings may be dominated by the shortest payback period could be ascribed to the choice of discount rate used in the analysis; a 2% and 4% rate may be too low to be feasible, even when the investment streams are controlled for inflation. Further analyses of this option would be interesting.

Internal rate of return

When options are similar, the IRR will favour the option with shortest payback period. When initial outlays differ, the IRR is biased towards the option with the lowest initial outlay and when lifetimes differ, the option with either the shortest payback period or the longest service lifetime will be favoured (Rapp, 1980). Where the reinvestment rates are not explicit, the IRR will again rank the option with the shortest payback period highest.

We would therefore expect the IRR to favour the natural gas spark engine CHP, as with an initial outlay of only € 90,000 and a lifetime of 20 years, it has both the lowest outline and the second-longest lifetime. However, once again, the wind electricity option ranks higher, influenced by an annual net benefit roughly twice as great as for the natural gas spark engine CHP option, i.e. the wind electricity option has the shortest payback period.

Profitability index – direction of bias

With similar options, the PI will be biased in favour of the option that provides the greatest return per unit invested. When options are dissimilar, the bias switches to the option with the shortest payback period.

Given that the PI is influenced by the return per unit, we would expect it to favour the option with lowest initial outlay, assuming returns are positive. For the options outlined in Table 2.2, this would be the natural gas spark engine CHP, and the rankings from Table 2.3 support this.

Suggestions for future avenues of research include determining the exact relationship between the differences in e.g. lifetime and initial outlays and the extent of the bias, and under what circumstances would the simple payback period provide equivalent rankings with the IRR and the PI.

2.6 Summary and conclusion

The purpose of this paper is to demonstrate that the choice of measure strongly influences the ranking of dissimilar options, and that the corrections suggested by conventional guidelines provide contradictory results. For the decision-maker who is not even aware of the existence of bias in comparisons of dissimilar options, this may result in undesirable investment selection.

As the most recent surveys suggest, the use of common capital investment measures such as NPV, IRR and PI are still widespread, and it is troubling that the lack of clarity in ranking dissimilar options found in leading textbooks and project guidelines provides such contradictory results.

The author asks that attention is directed towards this issue and modifications to textbooks and guidelines made available as soon as possible.

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Chapter 3. How the internal rate of return may bias energy investment rankings

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3.1 Abstract

This paper demonstrates how use of the internal rate of return (IRR) provides an implicit bias against renewable energy investments. Specifically, the paper focuses on one of the key issues with the IRR, the so-called reinvestment assumption, and demonstrates how the incremental rate of return can be used to overcome some of the issues of the IRR. Three energy technologies, a solar photovoltaic system, a biogas CHP plant and a natural gas engine CHP plant, are used as examples.

3.2 Introduction

Use of the internal rate of return (IRR) to rank investment alternatives has been a source of controversy in academia for more than five decades (*Alchian,1955; Dudley, 1972; Carlson et al.,1974; Rapp, 1980; Hajdasinski, 1997; Johnston et al., 2002;, Keef& Roush, 2001; Karathanassis, 2004; Kierulff, 2008; among others*). Perversely, it has been one of the most popular assessment tools used in investment decision-making within the same time frame, used in roughly 75% of surveyed firms almost or most of the time.(*Gitman&Forrester, 1977; Remer et al., 1993; Graham & Harvey, 2001; Ryan & Ryan, 2002; Brounen et al., 2004*).

The consequences of using IRR incorrectly to assess different investment options do not appear to communicate easily from academia to business. To illustrate the gravity of the situation, this paper compares the investment decision for an onsite combined heat and power (CHP) plant using fossil fuels against an onsite CHP plant using renewable fuels. Phung (1980) recommends using the IRR to determine which of two energy investments is profitable, assuming the cash flow stream is complete, but with comparisons of renewable and conventional energy technologies, this may result in significantly biased results.

The general characteristics of fossil-fuelled vs. renewably-fuelled energy technologies are uniquely suited for illustrating the extent of the error from using IRR to rank different investment options. Almost all renewable energy technologies (RETs) share the characteristics of initial high capital costs followed by a stream of relatively low variable costs over the lifetime of the investment, contrary to fossil fuel technologies (FFTs), which are generally characterized by initial low capital costs with relatively higher lifetime variable costs (partially due to the use of high-cost fuels). Rapp (1980) discusses the limitations of using IRR in comparing investments with different capital intensities and service lifetimes, finding that out of eight arguments in favour of using it, only two were wholly true. The most likely reason for its continued use in business, then and now, is ignorance of how the calculation works.

This paper contributes to the existing literature by arguing the existence of an implicit barrier to investments in RETs caused by the way investment decisions are generally made. Investors in particular should be made aware of the dangers in using IRR when facing RET investment decisions.

This paper is organized as follows. Section 3.3 introduces the IRR, its' key limitations, issues covered in the academic dispute and a brief overview of the survey literature on the prevalence of the IRR in the business world. Section 3.4 presents an investment comparison of a RET against a FFT and illustrates the magnitude of the bias resulting from inappropriate use of the IRR. Sections 3.5 and 3.6 discuss the results, possible consequences and conclude.

3.3 The Internal Rate of Return

The IRR is a project evaluation method/capital budgeting practice from the group of discounted cash flow methods commonly used alongside Net Present Value (NPV), which takes into account the time value of money, where a dollar today is worth more than a dollar tomorrow.

Following from Dudley (1972), the IRR is the discount rate that equates the present value of a flow of future investment returns with the present value of an investment (capital outlay). The IRR is frequently attributed to Irving Fisher's rate of return over costs concept from his publication *Theory of Interest* from 1930, but is more correctly attributed to Keynes' marginal efficiency of capital concept from his *The General Theory of Employment Interest and Money* from 1936 (*Alchian, 1955*).

The IRR is a function of the amounts of cash flows and their timing. Solving for the IRR, r, such that an investment (I) made in the current time period (t=0) is equal to the sum of future investment returns (R) over the lifetime of the project:

$$I = \frac{R_1}{(1+r)^1} + \frac{R_2}{(1+r)^2} + \ldots + \frac{R_n}{(1+r)^n} = \sum_{t=1}^{n} \frac{R_t}{(1+r)^t}$$

As the IRR is expressed as a percentage, it is an intuitively obvious measure of the benefits of a given investment, relative to the initial capital requirement. In order to evaluate a feasibility of a given investment, it must be compared to a hurdle rate, typically a company-specific cost of capital or minimum attractive rate of return. If a given project proposal results in an IRR greater than the hurdle rate, the project is usually undertaken.

Rapp (1980) composed a list of eight perceived key advantages of using the IRR as stated from advocates of the method. Some of these are (re)stated below[3]:

1. The IRR is easy to understand and to relate to rates reported from the bank
2. The IRR can be used without any previous knowledge of capital markets
3. The IRR is believed to be neutral across projects with different initial investments
4. The IRR is believed to be neutral across projects with different lifetimes

The first two arguments illustrate that the appeal of the IRR lies in its simplicity; the final two arguments a mistaken belief that the IRR can be used to compare mutually exclusive projects with different capital investments or lifetimes. This is not the case. Even the Fisher rate of return over costs, which is specifically formulated to compare two competing investment options, cannot accurately compute a rate for projects with different initial investments and different project lifetimes (Alchian, 1955).

Several issues with the IRR exist. A common problem, which is treated extensively in academic literature, is that the IRR is not necessarily a unique number; there can be none, one or more IRRs for a given project. This issue is not covered further in this paper, but the proof is easily obtained

[3] The remaining four are: 5) The IRR is approximately the same as the return per time unit per unit invested; 6) A close relationship is believed to exist between the growth of the firm and the internal rate of each project; 7) the IRR is believed to be neutral with respect to nominal or real prices; 8) the IRR is believed to take risk into account. The order of presentation has been altered from the original list.

mathematically by calculating the roots for an investment case with more than one negative value (investment) over a project period.

Prevalence of the IRR

Despite the several limitations of the standard IRR method, surveys of key decision-makers within companies indicate that it has been and continues to be a favourite tool when evaluating possible investments. Table 3.1 provides the proportion of decision-makers favouring IRR, contrasted with the proportion of decision-makers favouring NPV. The most recent surveys were conducted in 2001 for the US and 2002 for a small segment of EU countries. Between half and three quarters of decision-makers acknowledge using IRR most or all of the time when considering investment decisions.

Table 3.1 Overview of survey evidence on the popularity of the IRR

Author	**Survey Year**	**% IRR**	**% NPV**	**N firms**	**Region**
Gitman& Forrester (1977)	1976	53.6	9.8	112	US
Remer, et al. (1993)	1991	91	97	33	US
Graham & Harvey (2001)	1999	75.7	74.9	392	US
Ryan & Ryan (2002)	2001	76.7	85.1	205	US
Brounen et al. (2004)	2002	42.2-56	35-70	313	UK, Germany, Netherlands and France

The proportion of decision-makers favouring NPV is included for comparison purposes. The two are usually ranked equally. The NPV does not suffer from the same internal inconsistencies as the IRR, being more comparable to the MIRR, but is likewise not suited for comparisons of investments with different magnitudes or time periods.

3.4 Renewable Energy Investments

Assume a consumer is subject to a budget constraint and decides to choose between three energy alternatives. The first is a domestic photovoltaic system installed on a rooftop, the second a part ownership in a biogas-based combined heat and power (CHP) plant and the third a part ownership in a natural gas-based CHP plant. The consumer wishes to invest in the energy alternative which provides the greatest profit given a limited budget.

The technology characteristics of the PV system are taken from the Solar PV Consultation (CEPA & PB, 2011), the characteristics of the biogas-based CHP plant from information provided by Stirling.DK Ltd. (2012) and the specifications of the natural gas-based spark ignition engine CHP plant are taken from Technology data on energy plants (Danish Energy Agency, 2012). The physical location of the plant is assumed to be in the UK.

Key characteristics of the three different energy investments are provided in Table 3.2. It is assumed that the consumer's budget constraint is sufficient to cover the investment for the PV system or to purchase part ownership in either the biogas or natural gas CHP systems. An equally relevant assumption would be that the consumer has the budget to purchase either the biogas CHP or the natural gas CHP and multiples of the solar PV; the key point is that the investments are considered mutually exclusive and that the consumer is subject to a budget constraint. Under conditions of mutual exclusivity and budget constraints, it is not advisable to use NPV, IRR or the profitability index to select the most profitable investments (Brealey & Myers, 2003; Damodaran, 2011). However, it seems likely that decision-makers are almost always subject to a budget constraint and that they must choose an investment from a set of mutually exclusive options. The popularity of the IRR from Table 3.1 suggests that the IRR is used irrespective of the circumstances.

Table 3.2 Summary of energy investment characteristics

	Solar PV	**Biogas CHP**	**Natural gas CHP**
System electric output	2.6kW	35kW	60kW
System heat output	N/A	140kW	72kW
Total investment	EUR 11,250	EUR 125,000	EUR 90,000
Lifetime in years	35	15	15
Annual net return	EUR 1,050	EUR 20,200	EUR 18,300

Monetary values are rounded to the nearest 50.

All three energy plants are dissimilar in terms of energy output, technical characteristics and investment requirements.

The annual net return for the solar PV system is dependent on the annual operation and maintenance costs, sale of electricity to the grid and the feed-in tariff (CEPA & PB, 2011). Annual net returns for the biogas CHP are likewise dependent on annual operation and maintenance costs, sale of electricity to the grid and the feed-in tariff (in order of reference: Stirling.DK Ltd., 2012; EU, 2012; DECC, 2011). The biogas used as fuel is assumed equal to the value of heat, as might be the case where biogas is harvested from an anaerobic digester and the heat returned to drive the anaerobic process (Stirling.DK Ltd., 2012). Annual net return for the natural gas CHP comprises of annual operation and maintenance costs, sale of electricity to the grid, sale of heat and fuel costs (Danish Energy Agency, 2012; EU, 2012).

The IRR estimates from the three investment options are summarized in Table 3.3.

Table 3.3 IRR estimates for the three energy alternatives

Hurdle rate = 6%	**Solar PV**	**Biogas CHP**	**Natural gas CHP**
IRR	8.8%	13.8%	18.8%

For the decision-maker who prefers to use the IRR, the investment decision appears to be straightforward. Although all the projects clear the hurdle rate, the natural gas CHP investment clearly provides higher returns.

The Reinvestment Assumption of the Internal Rate of Return

There are two key issues with the IRR which will be discussed in greater detail here. One is the limitations of the IRR as a tool for evaluating investment decisions, not just across heterogeneous investment projects but also for a single investment project with intermediate cash flows. A source of controversy in the literature, known as the reinvestment assumption, is how to treat intermediate cash flows from a given investment project until the end of the project lifetime. In cases where the reinvestment rate is not explicitly accounted for, the IRR of a single project can substantially overstate the perceived benefits of the initial investment.

Borrowing loosely from Hajdasinski (2000), imagine the following investment stream based on a 2.6 kW household photovoltaic (PV) installation with a 35-year lifetime.

$$[1]: \{-11{,}250;\ 1{,}050; \dots ; 1{,}050\}$$

defined within a time period of 36 years (t=35). The project consists of an investment in time t=0, followed by 35 positive returns on investment in the time period from t=1 to t=35. The investment results in a unique IRR of 8.8%.

The investment can be broken down from one initial investment of 11,250 at t=0 to 35 smaller investments in the time period from t=1 to t=35, each producing a unique IRR of 8.8%. Table 3.4 shows the investment at time t=0 if only the first 5 years are considered. Each subsequent year requires a smaller proportion of the initial investment as this investment 'works' for a longer number of years, earning a higher return per Euro invested.

Table 3.4 Breakdown of IRR calculation for solar PV installation, first five years

EUR	t=0	t=1	t=2	t=3	t=4	t=5	IRR
	-950	1,050					8.8%
	-900	0	1,050				8.8%
	-800	0	0	1,050			8.8%
	-750	0	0	0	1,050		8.8%
	-700	0	0	0	0	1,050	8.8%
Total	-4,100	1,050	1,050	1,050	1,050	1,050	8.8%

All values rounded to the nearest 50.

The investment is split along the lifetime of the solar PV system. Each part represents a decreasing portion of the initial investment; the five years in Table 3.4 represent 36.4% of the initial investment.

The controversy surrounding the reinvestment assumption is simply the question of what happens to the investment return of 1,050 at t=1 for the rest of the project lifetime? Presumably, an income received during a project will be put to good use elsewhere, earning an interest, rather than collected and left in a drawer somewhere. The same question can be applied to the other intermediate earnings; only the investment return at t=35 reflects the proportion of the original investment working throughout the project lifetime.

To illustrate, assume the intermediate investment returns could be reinvested at the same rate of return (8.8%) for the duration of the project lifetime and cashed in at t=35. This is shown in Table 3.5.

Table 3.5 Breakdown of IRR calculation to demonstrate implicit reinvestment assumption

EUR	t=0	t=1	t=2	t=3	t=4	t=35	IRR
	-950	0	0	0	0	18,450	8.8%
	-900	0	0	0	0	16,950	8.8%
	-800	0	0	0	0	15,600	8.8%
	-750	0	0	0	0	14,300	8.8%
	-700	0	0	0	0	13,150	8.8%
Total	-4,100	0	0	0	0	78,500	8.8%

All values rounded to the nearest 50.

Table 3.5 demonstrates the overall IRR and intermediate IRRs remain at 8.8% with an assumed reinvestment rate of 8.8%.

These two investment streams are equivalent; in other words, when using the standard IRR, we implicitly assume that the intermediate investment streams are reinvested at the overall IRR.

If we instead assume that the intermediate investment returns can be reinvested at a slightly lower rate representing a consumer's hurdle rate, for example 6%, the investment returns differ somewhat. These are shown in Table 3.6.

Table 3.6 Breakdown of IRR calculation with hurdle rate

EUR	t=0	t=1	t=2	t=3	t=4	t=35	IRR
	-950	0	0	0	0	7,600	6.1%
	-900	0	0	0	0	7,200	6.2%
	-800	0	0	0	0	6,750	6.2%
	-750	0	0	0	0	6,400	6.3%
	-700	0	0	0	0	6,000	6.4%
Total	-4,100	0	0	0	0	33,950	6.2%

All values rounded to the nearest 50.

The overall IRR has decreased from 8.8% to 6.2% to take into account the lower investment returns earned on capital reinvested at 6%. Note that there would be no change to the 35th investment portion, which retains a rate of return of 8.8%, signifying that this proportion of the investment is employed continuously until the project termination. The greater the difference between the calculated IRR and the choice of reinvestment rate, the greater the overstatement of the IRR. The adjusted IRR for the biogas CHP system is 9.2% (relative to an IRR of 13.8%) and 10.9% (relative to an IRR of 18.8%) for the natural gas CHP system.

This variation of IRR, where the rate of reinvestment is explicitly determined, is known as the modified internal rate of return (MIRR), the external rate of return (ERR) or the true rate of return (TRR), among others. It avoids known issues of the IRR, including ranking discrepancies relative to NPV calculations (Carlson et al., 1974; Dudley, 1972; Johnston et al., 2002; Hajdasinski, 1997; Karathanassis, 2004; Keef& Roush, 2001; Kierulff, 2008). Kierulff (2008) also shows that the MIRR counters the lack of a unique IRR for investment streams with multiple net negative returns.

The Incremental Internal Rate of Return

While the MIRR deals adequately with the overstatement bias of the IRR, it cannot counter the inadequacy of the IRR for comparisons across mutually exclusive projects. Instead, an incremental approach is needed.

IRR calculations may give inconsistent results when investments with differing initial investment magnitudes are compared to each other. Hajdasinski (2004), Kierulff (2008) and Remer & Nieto (1995) recommend using the incremental approach for such a comparison. The incremental investment stream is calculated by subtracting the smaller initial investment stream from the larger initial investment stream. The IRR of this investment stream is then calculated and compared to the identified hurdle rate. These incremental investment streams are shown in Table 3.7.

Table 3.7 Comparison of incremental investment streams

Investment	t=0	t=1	t=35	IRR	MIRR	Hurdle rate
Biogas CHP – Gas CHP	-35,000	1,900	0	-3%	4%	10%
Biogas CHP – Solar PV	-113,750	19,150	-1,050	14%	11%	10%
Gas CHP – Solar PV	-78,750	17,250	-1,050	20%	12%	10%

All values rounded to the nearest 50.

For the above three examples, the calculated MIRR and IRR values suggest the same ranking as in a direct comparison with IRRs. Based on the IRR calculation alone, a decision-maker would clearly favour the natural gas CHP.

As discussed earlier, when faced with a comparison between two investment options with differing initial investment magnitudes, the best method is to calculate an incremental IRR or MIRR. While the rankings were maintained in the examples provided in this paper, it is highly unlikely that this will be true across all comparisons.

None of the included surveys in Table 3.1 appear to have included incremental IRR as an evaluation tool, so it is difficult to assess directly the prevalence of incremental IRR. Surveys which have included the modified IRR generally find them to be among the least popular tools used, but there is hope that it will gain in popularity over time.

3.5 Discussion

The above example is just one of many that could have been included to illustrate the inherent bias in investment decision-making. Especially projects with a long lifetime and a high initial investment are likely to suffer from the time constraints that the decision-makers operate under which cause them to favour simplicity over accuracy.

This bias may also go some way to explain why even well-reasoned policies do not always succeed in shifting markets. In the UK, for example, all policies go through a highly detailed cost benefit analysis in order to set levels which will reflect the optimal subsidy level to move a potential investment above the market hurdle rates (for instance, see CEPA & PB, 2011).

However, these highly detailed and accurate analyses fail to address the systematic error perpetuated by decision-makers when they choose to judge projects by their IRR. This miscommunication between policy-makers and decision-makers is tragicomic in its extremes, especially when it leads to a continued adjustment and readjustment of existing policies in an effort to uncover the source of the discrepancy.

3.6 Conclusion

A natural extension of this paper would be a short survey sent out to company decision-makers in order to judge their awareness of the shortcomings of the IRR. In particular, it would be interesting to uncover:

- if both IRR and NPV are used to judge investment decisions, which measure is favoured when there is a ranking discrepancy
- the familiarity and awareness of MIRR as a counter to inflated IRR values
- the familiarity and awareness of incremental IRR for ranking investment decisions

An additional extension is suggested by the results of the survey literature covered in this paper, some of which indicates that smaller-sized firms are more likely to use even simpler methods when facing investment decisions, such as the payback period. Whether this is likely to result in inherent bias as well is uncertain but seems highly likely.

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Chapter 4. The impact of policy support on the return from small-scale biomass investments: A case study comparison of Germany, the UK and Denmark

Paper status

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4.1 Abstract

Investment cases are prepared for a Stirling-powered woodchip combined heat and power plant with an electrical capacity of 140 kW and a thermal capacity of 560 kW, for a general case in Germany, the UK and Denmark. Existing national financial support schemes are included for each of the three countries. The impact of the support schemes on the net present value in each case is assessed. Differences between the three countries are discussed, particularly with regard to differences in national energy prices, renewable energy ambitions and existing energy profiles. The focus of this article is on how well the assessed renewable energy support schemes function in overcoming market barriers from the viewpoint of the private sector investor.

4.2 Introduction

There is significant debate about the optimal design of financial support schemes to promote the use of biomass in energy generation. Rather than contributing to the extensive theoretical literature on the subject, this paper provides a case study comparison of the impact of current schemes in Germany, the UK and Denmark on the economic viability of a small-scale biomass energy technology from the viewpoint of the investor.

Although the technology application is the same in all three cases, the structural differences between the three countries result in differences in the amount and type of support offered and its' impact on the investment payoff. Differences between the three countries are discussed, especially with regard to differences in national energy prices, renewable energy ambitions and existing energy profiles.

While significant literature exists on barriers to renewable energy uptake, policy design and the promotion of technological innovation, few papers deal with the investor perspective on renewable energy policy design (Bürer and Wüstenhagen, 2009; Dinica, 2006; Loock, 2012). The literature review revealed no papers on whether a given financial support scheme was successful in promoting the decision to invest for the individual investor.

The contribution of this paper is therefore: to illustrate exactly how financial support schemes affect the decision of the investor to invest or not invest; to compare the impact on the investment decisions across Germany, the UK and Denmark; and to discuss the significance of the financial support schemes relative to the existing market conditions.

The paper is set up as follows. Section 4.3 introduces the technology which forms the base of the investment case study, provides an overview of the three countries compared and narrows down which policy types are considered. Section 4.4 gives a more in-depth overview of the three member states' energy policies, focusing on current policies which are relevant to the investment case. Section 4.5 describes the standard methodology used in the investment case, and delivers the results from the base case in each country. It ends with comparison of the results across the countries considered. Section 4.6 provides a discussion of the results, namely identifying which policies have the greatest impact on the investment returns and why. Section 4.7 concludes with lessons learnt and contains recommendations for policy makers.

4.3 Case study profiles

All the case studies are based on a 4-engine woodchip fired combined heat and power (CHP) plant, courtesy of Stirling.DK Ltd. (SDK). The 4-engine Stirling plant has a nominal output of 140 kW electric and 560 kW thermal energy, which is roughly equivalent to the annual consumption of 360 100-square metre (sqm) flats (see Table 4.1 for details).

The SDK CHP plant is an alternative to either small-scale natural gas-fired CHP or small heat-only biomass boilers. The plant is based on the 35 kWe Stirling engine, specifically developed for combustion of low-quality bioenergy. The updraft gasification plant is modular, and comes in the following sizes:

- 35 kW electrical and 140 kW thermal (1-engine plant)
- 70 kW electrical and 280 kW thermal (2-engine plant)
- 140 kW electrical and 560 kW thermal (4-engine plant)

A 1-engine plant provides enough heat and power for app. 70-90 typical 100 sqm Copenhagen flats. Table 4.1 shows the key characteristics of a 1-engine plant. The system is scalable up to 4 engines.

Table 4.1 SDK CHP Facts and Figures

No. of engines	**1**
Electric output (kWe)	35
Heat output (kWth)	140
Fuel consumption (kg/hour)[1]	70
Yearly power production (MWh)[2]	210
Yearly heat production (MWh)[2]	840
Yearly fuel consumption (tons/year)[1,2]	420
Saved CO2-emissions (tons/year)[3]	240
Number of households supplied	90

[1]Based on fresh woodchips with a moisture content of 42% and overall CHP plant efficiency of 89.2%.[2]Based on 6,000 hours of operation.[3]Based on CO2 emissions of 56.7 kg/GJ4.For an average annual consumption of 2.1 MWh of electricity and 9.3 MWh of heating for 2 people in a 100 sqm flat.

The system is designed for heat-driven, baseload operation and is therefore optimally suited for sites with a relatively constant heat demand throughout the year, such as district heating plants, swimming pools, hotel and leisure centres, and hospitals. The technology satisfies the most stringent requirements from applicable environmental legislation in the three countries considered. Further consideration to applicable environmental legislation is therefore not paid in this paper.

The European Union (EU) Directive 2009/28/EC (European Parliament, 2009) promotes the use of policy support to encourage market demand for renewable energy. The scope and scale of this is primarily left to the individual member states, with the caveat that certain targets are reached by 2020 and a biannual progress report is submitted for review.

Three EU countries are considered in this paper: Germany, the UK and Denmark. Germany passed an active renewable energy policy in 1974 following the first oil crisis in 1973 (Lauber& Metz, 2004). Denmark followed suit in 1976 (Basse, 2011), as did the UK in 1988 (Costa et al., 2008). None of the three countries had a statistically relevant share of renewable energy in their national energy mix prior to initiating policies to promote renewable energy sources (RES).

Denmark was the most reliant on energy imports, with 93% of the energy supply based on imported oil. Denmark was also the only of the three countries to reject the construction of nuclear power plants, and the combination of desired self-sufficiency coupled with a strong anti-nuclear lobby helps explain the relatively high adoption rates of RES compared to Germany and the UK.

Table 4.2 shows the comparison between current proportions of renewable energy for heat and electricity sources and the EU 2020 targets for each member state.

Table 4.2 Comparison of the renewable electricity and renewable heat sources for Germany, the UK and Denmark

Proportion of renewable energy sources in the electricity and heat supply	**Proportion of renewable electricity**	**Proportion of renewable heat**
Germany 2010 ***2020 Target***	16.8% *35%*	9.8% *14%*
UK 2010 ***2020 Target***	7.4% *30%*	1.8% *12%*
Denmark 2009 ***2020 Target***	27.4% *51.9%*	19.6% *39.8%*

Sources: BMU, 2010; DECC, 2012; Danish Energy Agency 2010

Germany and the UK are two of the largest economies in the EU, representing over 33% of the EU-27's combined gross domestic product in 2010 (controlled for purchasing parity standards). The Danish economy is approx. one tenth of the UK economy (Eurostat, 2010). Germany and Denmark are two of the first countries to use national policies to promote the integration of renewable energy sources into the energy supply mix (Lauber& Metz, 2004; Basse, 2011). Denmark is the only EU member state which is not reliant on net energy imports (EU Energy website, 2012). The UK has one of the lowest starting points for integration of renewable energy sources into the energy supply (only Luxembourg and Malta were lower in 2008) (EU Energy website, 2012).

In other words, the three selected countries represent a disparate picture of economic clout, current energy profiles and future energy ambitions. Further country profiling is given in the following section, as well as an assessment of what impact this might have on country policies.

The focus of this paper is on how well national policies support renewable energy investments. By taking a specific technology case and applying the same technology in three separate countries, it should be possible to ascertain how successfully the policies overcome market barriers in order to generate sufficient returns to investment.

As it is a general case, only nation-wide policies are considered. Additional policies, for example region-specific policies for promotion of industry in less economically successful areas, are not included in the case studies. The same applies to policies targeting specific consumer groups, e.g. municipalities, who may receive additional support.

For the same reason, national estimates of fuel costs, heat and electricity prices, corporate taxation levels etc. are used where available and approximated where not. These restrictions will likely reduce the returns from investment. The technology type considered is especially suited for remote, forested/agricultural regions where additional support is most likely and fuel costs etc. are lower.

As the purpose of the paper is not to make a case that such investments are generally profitable, but rather to assess the magnitude of the impact of renewable energy policies on an applicable technology, the level of this bias is not deemed critical to the results.

Renewable cooling is included in the fractions of renewable heating reported where possible. Renewable cooling is otherwise disregarded in this paper. Likewise, the share of renewables in transport is included in the reported figures for total energy consumption but is otherwise ignored.

4.4 Member state policy profiles

Germany has one of the longest histories in support for renewable energy generation, introducing tariffs to stimulate electricity demand from renewable energy sources already in 1979 (Lauber & Metz, 2004). In 2010, 11% of final energy consumption was sourced from renewable resources, with the bulk coming from bioenergy (7.9%) (BMU, 2011).

Bioenergy is a significant contributor to energy from renewable resources in Germany, representing 33% of the renewable electricity supply and 92% of the renewable heat supply in 2010.

Given its widespread use, barriers to biomass energy technologies are likely to be small and biomass supply chains are likely to be advanced. These factors will lower the investors' perception of risk and require lower investment returns for project viability.

The strongest financial support scheme for small-scale biomass energy systems in the German market is the current feed-in tariff structure, EEG 2012 (Federal Law Gazette, 2011), which especially favours small-scale technologies and is state-guaranteed for a 20-year period.

From January 2009 onwards, the Renewable Energy Heat Law, EEWärmeG, required that all owners of new buildings must cover part of their heating demand using renewable energy sources; for CHP a minimum of 50 % coverage is required, either through direct heating or via a grid connection (BMU, 2012). Policies such as this, which are incorporated into building regulations, are referred to as 'use obligations' in this paper.

The KfW bank group provides soft loans (favourable low-interest loans) to finance renewable energy investments for most groups of investors across Germany (KfW, 2012). These soft loans are not considered explicitly in the investment case in section 4.5.

Table 4.3 gives a quick overview of relevant current policies and their targeted areas; 'CHP' refers to combined heat and power, 'E' refers to electricity from renewable resources and 'H' refers to heating (and cooling) from renewable resources.

Table 4.3: Overview of existing policies applicable to small-scale biomass CHP in Germany, the UK and Denmark

Country	Year	Feed-in tariff/ bonus	Soft loans	Quota scheme	Tax exemption	Use obligation
Germany	2009	E (ends 2012)	CHP, H			H
Germany	2012	E				
UK	2001				E, H, CHP	
UK	2002			E		
UK	2010	H				E, H
Denmark	1977				E, H, CHP	
Denmark	1993/1997				CHP	
Denmark	2009	E				

The UK has one of the most aggressive strategies for promoting renewable energy generation. A wide range of incentives and penalties are in place to promote renewable energy uptake, including tax relief and additional taxes, use obligations for onsite generation and tariffs for both heat and electricity from renewable resources.

In 2010, 3.3% of the total final energy consumption was derived from renewable energy sources, with roughly two thirds derived from bioenergy sources. Similar to Germany, bioenergy is a significant contributor to renewable electricity and heat, with 77% of renewable electricity and 88% of renewable heat derived from bioenergy sources (DECC, 2011).

Comparing with the German targets and status in Table 4.2, it is apparent that while the targets are not much different, the current status of renewable energy deployment is much lower in the UK than in Germany. For example, the heat supply target for Germany is 14% and the 2010 status is close to 10%, whereas the target for the UK is 12% and the 2010 status is only 2%.

Given the difference between existing levels of renewable energy and the targets for 2020, the UK policy for promoting renewable energy sources is necessarily more aggressive than in Germany.

Altogether, four different support mechanisms have been identified for the general case:

- Renewable Obligation Certificates (ROCs)
- Renewable Heat Incentive (RHI)
- Enhanced Capital Allowance (ECA)
- Levy Exemption Certificates (LECs)

ROCs are certificates issued to accredited generators for eligible renewable electricity generated within the UK and supplied to customers within the UK by a licensed electricity supplier. The operators of the generators are free to trade the certificates with one another under market conditions. Electricity suppliers use ROCs to demonstrate that they have met their obligation to source electricity from increasingly renewable resources. If they do not earn sufficient certificates on their own and do not purchase enough from other suppliers they are required to pay an equal amount into a common fund, which is subsequently distributed back to suppliers who have met their obligations. One to two ROC(s) are issued for each megawatt hour (MWh) of eligible renewable output generated (Ofgem, 2012).

The RHI is a new tariff system introduced in 2011, payable to energy users generating their own heat from renewable sources. The tariff is payable per MWh of metered ‘useful’ heat generated on site. Currently, the scheme is only applicable to commercial owners, but it is expected to be expanded to private consumers in 2013 (DECC, 2012).

The ECA allows the full cost of an investment in designated energy-saving plant and machinery to be written off against the taxable profits in the period in which the investment is made. This is particularly useful for commercial operators, as the write-off can be subtracted from the company's annual taxable profit, rather than just the plant-specific profits (DECC, 2012b). The ECA is not considered explicitly in the investment case in section 4.5 as it is assumed the investment is made in a period prior to the first operating year and is therefore not relevant to the case study at hand. In a more realistic scenario the investor would have other profit streams in the year the investment is made and would be able to apply ECA to those profits.

LECs are an exemption from a tax on energy delivered to non-domestic users in the United Kingdom aimed at providing an incentive to increase energy efficiency and to reduce carbon emissions. The exemption applies to high-quality CHP generation. Profits from the levy are administered in a fund and redirected to promote renewable energy initiatives (Ofgem, 2012b).

Interestingly, this form of levy cannot be applied in Germany as it would go against Germany's constitutional levy provisions (Bürger et al., 2008).

In 1973, at the time of the first energy crisis, 93% of the Danish energy supply was based on imported oil. From 1997 to the present, Denmark has been a net exporter of energy, where exports of the Danish natural gas and oil reserves from the Northern Sea have eclipsed coal imports. This remarkable shift from energy dependency to energy independency evolved alongside a powerful anti-nuclear lobby, which decisively rejected nuclear power plant construction in the 1985 energy plan (Vleuten & Raven, 2006).

This anti-nuclear sentiment helps explain the relatively high proportions of renewable electricity and renewable heat in the existing energy supply, seen in Table 4.2. Without nuclear power as an option, the Danish government turned towards promotion of decentralized energy production from natural gas and renewable resources. In 2010, 40% of electricity production was from decentralized units and wind parks. District heating was the dominant form of household heating, with a share of 61.7% in 2010 (Danish Energy Agency, 2010).

The share of renewables in the final energy consumption was roughly 20% in 2010, and bioenergy contributed to roughly 75% of all renewables consumed in Denmark. The share of bioenergy in renewable electricity production was 60.5%, and 99% in renewable district heating production (Danish Energy Agency, 2010).

The principal policy support mechanism in Denmark available for the technology under consideration is a feed-in tariff for electricity fed into the grid. However, the key financial incentives for onsite production of heat and electricity from renewable energy resources are in the form of avoided carbon and energy taxes. For electricity production consumed onsite there is a further tax incentive from a substantially reduced public service obligation surcharge (PSO), which is similar to the UK climate change levy.

4.5 Investment cases

This section provides a brief overview of the standard assumptions and methodology followed in the investment cases, followed by country-specific assumptions and the returns to investment and concludes with a comparison of the results.

All values are reported in Euro. For values originally in Pounds Sterling, a conversion rate of EUR 1.2 to the Pound was assumed. For values originally in Danish Kroner, a conversion rate of DKK 7.46 to the EUR was assumed.

Technical data on the plant is taken as given from the equipment supplier. Estimates on total installed costs and annual service costs are likewise taken as given. These cost assumptions include estimates of installation costs, transport costs and operating costs of the supplier of the equipment/plant owner. Land cost is not included.

For confidentiality reasons, the exact specified investment costs are not reported in this paper. A total investment estimate is given, based on current 2012 costs. Likewise an overall estimate of the annual service costs (operation costs) is given.

It is assumed that all plants are purchased and installed in 2012 and begin energy production on the 1st of January, 2013. It is further assumed that the investment is paid in full in 2012.

All prices are in nominal values; i.e. indexed to predicted inflation increases. For simplicity, and to facilitate comparison, the UK Treasury GDP deflators from December 2010 have been used for all three countries. The deflator is set at 2.7% from 2015 onwards.

The net present value (NPV) and internal rate of return (IRR) are used to calculate the returns to investment:

Solving for NPV, such that an investment made at time t=0 (I_0) is subtracted from the sum of the future net benefits (*NB*) over an investment's lifetime (*t=0,…,n*), each of which is weighted by the discount rate (*r*) at time *t=n*;

$$NPV = -I_0 + \frac{NB_1}{(1+r)^1} + \frac{NB_2}{(1+r)^2} + \ldots + \frac{NB_n}{(1+r)^n} = -I_0 + \sum_{t=1}^{n} \frac{NB_t}{(1+r)^t}$$

The NPV is expressed in a given currency and is stated in absolute terms. The discount rate is expressed as a constant percentage. The accept/reject decision for an option requires a positive NPV, i.e. an NPV value greater than zero.

Solving for the IRR, *r*, such that an investment (*I*) made in the current time period (*t=0*) is equal to the sum of future net benefits (NB) over the lifetime of the investment:

$$I_0 = \frac{NB_1}{(1+r)^1} + \frac{NB_2}{(1+r)^2} + \ldots + \frac{NB_n}{(1+r)^n} = \sum_{t=1}^{n} \frac{NB_t}{(1+r)^t}$$

The IRR is expressed as a percentage and measures the benefits of a given investment relative to its initial outlay (or the costs relative to an initial payout). The accept/reject decision of a given investment must be compared to the identified hurdle rate. If a given investment proposal results in an IRR greater than the hurdle rate, the proposal is judged profitable.

Table 4.4 gives the technical characteristics of the plant considered (as given by the equipment supplier):

Table 4.4: Technical characteristics of base case technology

Characteristic	Efficiency	Effect
Input	-	800 kW
Overall output	88%	704 kW
Heat output	70.5 %	564 kW
Electrical output	17.5%	140 kW
Own electrical consumption	-	20 kW
Net electrical output	15%	120 kW

The plant is assumed to have an availability of 80%, equivalent to roughly 7,000 hours, operating at full load.

Table 4.5 gives the financial characteristics of the base case technology. The annual service cost reflects the value in 2013, i.e. including one year's worth of inflation. The total investment cost includes equipment costs, transport, installation and building requirements but not value-added tax. Insurance cost has been set equal to 1% of the original investment value and increases at the rate of inflation. A conservative estimate of a scrap value equal to nil has been set.

Table 4.5: Financial characteristics of base case technology

Characteristic	Value
Lifetime	15 years
Annual service cost (2013-value)	€ 57,809
Total investment cost (2012-value)	€ 1,200,000
Insurance cost (2013-value)	€ 12,312
Scrap value	€ 0

Income, for example from the receipt of subsidies, is assumed to be paid in full in the year of generation.

All customers are assumed to be commercial operators; i.e. not private individuals. For example, a group of homeowners investing in the technology as a cooperative would be classified as commercial owners and set up the plant as a limited company. Taxes are paid on the EBITDA (earnings before interest, taxes, depreciation and amortization), after depreciation.

It is assumed that all the investments are 75% financed through a loan with a net interest rate of 10%, and 25% financed through equity with a cost of capital of 19%. This gives an overall rate of 10%. Interest payments are not included in the cash flow, but rather through the discount rate in the NPV calculations. This discount rate is equivalent to a company's weighted average cost of capital (WACC) or minimum attractive rate of return (MARR) on an investment.

The results from the respective investment cases are reported as a NPV, a discounted payback period and an IRR. Only investments with a positive NPV, a discounted payback period less than the investment lifetime and an IRR higher than the discount rate are considered worthwhile.

German investment case

In addition to the general assumptions given above, there are several applicable country-specific assumptions.

Fuel cost: the cost of the woodchips is taken from the CentralesAgrar-Rohstoff-Marketing- und Entwicklungs-Netzwerke.V. (C.A.R.M.E.N.). The average value across North and South for the first quarter of 2012 for woodchips with a moisture content of 35% is used. This price is listed as € 90.42/ton, corresponding to a fuel cost of € 0.028 per kWh (2012 prices) (Carmen-ev, 2012).

Value of heat: it is assumed that all the heat produced from the plant is consumed onsite. As a natural gas CHP plant was identified as a possible substitute for the SDK CHP plant, the natural gas price is used as a base value to calculate the value for heat. A natural gas price of € 0.0504 is taken from the European Commission's Energy Portal. This value is from November 2011, as reported for industrial consumers who consume 0.25 GWh of natural gas annually. The price includes the wholesale price, transmission, distribution and administration costs and non-recoverable taxes, i.e. VAT is not included (EU Energy website, 2012).

The value is then divided by a factor of 0.8 in order to correct for some generation costs and conversion losses. This gives a value for heat of € 0.063.

Corporate taxation is estimated at 30%, consisting of a corporate tax rate of 15.8% (including the solidarity surcharge) and a municipal tax which may vary between 14 and 17%. The rate of 30% represents the lower bound of what would typically be found (Deloitte, 2011).

Depreciation: in Germany, it is recommended that capital investments are depreciated using the straight-line method (Deloitte, 2011). Only the original capital equipment is depreciated in this investment case.

Income from subsidies: it is assumed that the net electricity produced is sold to the net in return for the EEG 2012 tariff (Federal Law Gazette, 2011), based on plant commissioning in 2012. The base tariff for a 140 kW electric biomass plant is € 0.143 per kWh, and is set for 20 years. An additional bonus is available, depending on the biomass material used in the plant; for example, wood from energy crops is classified as substance class I, and wood from landscape management is classified as substance class II. The first gives a bonus of € 0.06 per kWh and the second a bonus of € 0.08 per kWh. For simplicity, it is assumed that the material used to fuel the plant is from energy crops and therefore gains a total tariff of € 203 per MWh delivered electricity. Note that this value stays constant over the lifetime of the plant, i.e. it is not corrected for inflation.

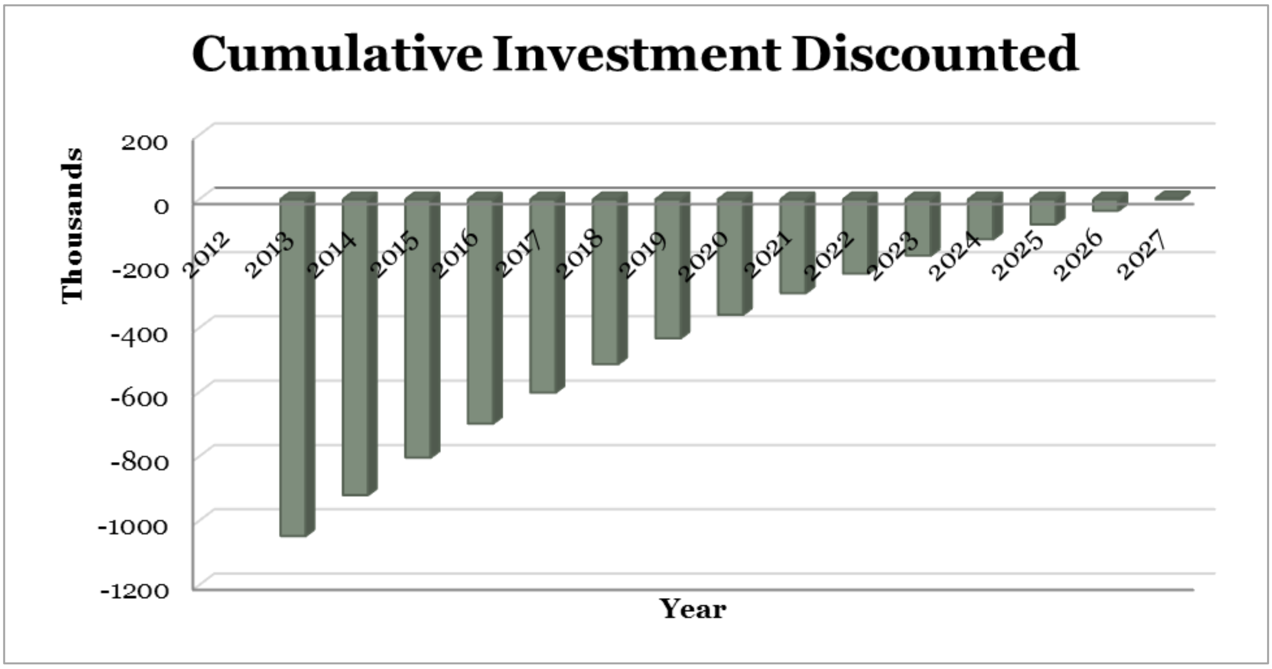
The returns from the investment are given in Table 4.6.

Table 4.6: Returns from investment in Germany

Investment measure	Value
NPV (@10% discount rate)	€ 3,109
IRR	10%
Discounted payback period	15 years

The values above are positive, meaning that the investment returns exceed the hurdle rate set by the 10% discount rate. The discounted, cumulative cash flow from the investment in Germany is illustrated in Figure 4.1:

Figure 4.1 Discounted, cumulative cash flow for Germany



Without the income from the EEG, the returns from investment would not exceed the investment costs. The income from the EEG corresponds to roughly 40% of the total income of the plant, decreasing over time, to roughly 32% at the end of the investment period.

The only other source of income for the plant is the value of the heat generated. Although the amount of heat generated is 4 times the amount of electricity, the total value is only 1.5-2 times greater. If the plant operator was to consume the electricity onsite instead of selling it at the base tariff, assuming a value of € 0.134 per kWh (EU Energy website, 2012), the income of the plant would not be sufficient to pay back the investment in the 15-year time period.

UK investment case

Fuel cost: Fuel cost is based on the values from the UK Biomass Energy Centre website (Biomass Energy Centre, 2012). A price of £90/ton is assumed, for woodchips with a moisture content of 30%, giving a fuel cost of € 0.031 per kWh.

Value of heat: It is assumed that all of the heat is consumed onsite. The same approach applied to Germany is used, although the equivalent natural gas price for the UK is only € 0.0392 (EU Energy website, 2012). Using the same correction factor of 0.8, this gives a value for heat of € 0.049.

Value of electricity: A similar approach is followed for electricity. It is assumed that all electricity is consumed onsite. The stated value for electricity on the Energy Portal for industrial consumers using 2 GWh/year is € 0.1149 (EU Energy website, 2012). No correction factor is applied.

Corporate taxation: The corporate taxation level is currently at 24%, but is predicted to decrease to 23% in 2013 and remain there from then onwards (HM Treasury, 2012).

Depreciation: In the UK, it is recommended that capital investments are depreciated using the reducing balance method at a rate of 20% per year (Worldwide tax, 2012). Only the original capital equipment is depreciated.

Income from subsidies: There are three separate income sources from subsidies accounted for in this investment scenario. All subsidies increase with inflation, in contrast to the German investment case.

ROCs: renewable obligation certificates are issued to the supplier per MWh renewable electricity generated and redeemed at market prices. For simplicity, a value for 1 ROC is set equal to £ 40.69 (~ € 48.8) (DECC, 2011b). Dedicated biomass plants with CHP are eligible for 2 ROCs per MWh electricity generated or 1.5 ROCs in combination with the RHI subsidy. For this investment case, it is assumed that 1.5 ROCs are given. The value of the ROCs is discounted to 89% of their value in order to take into account power purchase agreement (PPA) costs. This value sums to € 65.19 per net MWh generated.

LECs: levy exemption certificates also vary over time but are assumed to have a base value of £ 4.72 (~ € 5.66) per MWh. The value of the LECs is discounted to 93% to reflect PPA costs (DECC, 2011b).This sums to € 5.27 per net MWh generated.

RHI: Solid biomass CHP with a thermal output between 200 kW and 1,000 kW qualifies for £ 47 (~ € 56) per MWh for the first 1,314 hours of full-load operation and £ 19 (~ € 23) per MWh for the remainder (DECC, 2011d). No discounting is applied, as it is uncertain whether something similar to the PPA would apply.

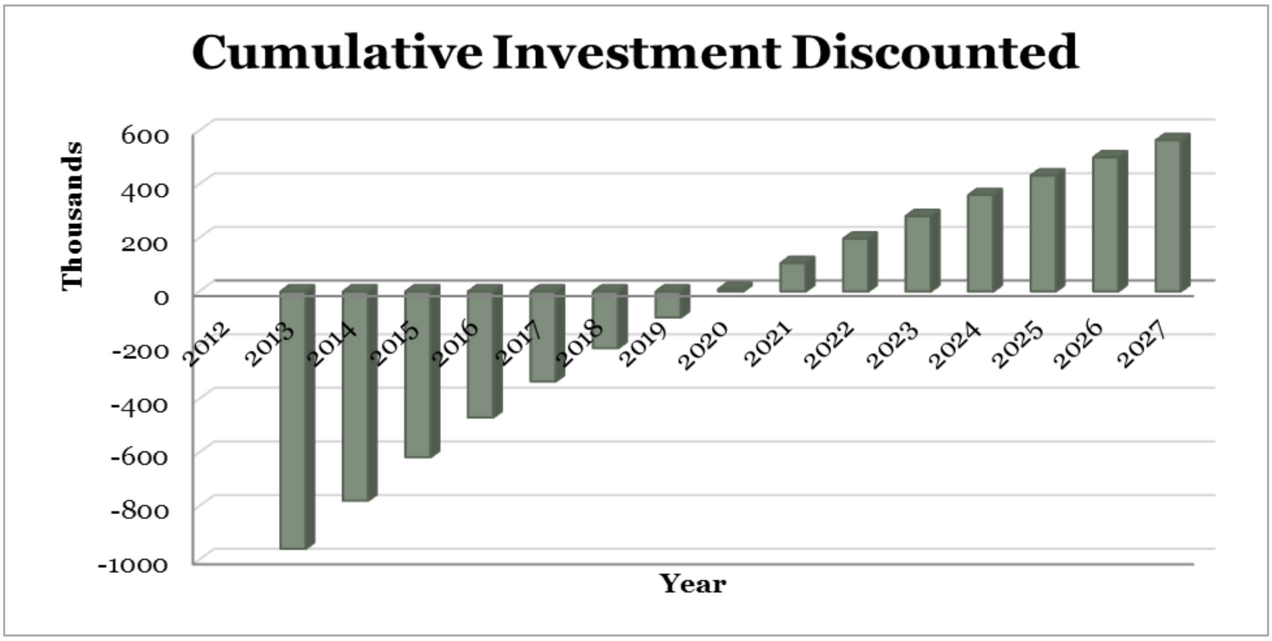
The returns from the investment are given in Table 4.7.

Table 4.7: Returns from investment in the UK

Investment measure	Value
NPV (@10% discount rate)	€ 563,722
IRR	17.5 %
Discounted payback period	8 years

All the values are significantly higher than those reported for Germany, which is clear from2.2.

Figure 4.2 Discounted, cumulative cash flow for the UK



Interestingly, the proportion of subsidy income relative to total plant income is very similar to the German investment scenario, at 37.5%. Likewise, the ratio of heat income to electricity income is roughly 2:1.

The main difference between the two is that the EBITDA value is slightly higher in absolute terms; the margin relative to total income is a constant 49% for the UK investment case and 35-38% for the German investment case. This difference between the returns on the two investment scenarios can largely be ascribed to the subsidy income following inflation in the UK but remaining constant in Germany.

Without the RHI, the investment returns would not be able to pay back the investment costs, even given 1.5 ROCs and the LECs. This would hold even if 2 ROCs were granted instead of 1.5. However, if the ROCs were removed, but the RHI and LECs retained, the investment would still have a positive return.

Danish investment case

Fuel cost: Fuel cost is based on deliveries made to a 1-engine plant onsite in Denmark, at the SDK headquarters. This price reflects the upper bound of what would be expected, as the delivery is for a 1-engine plant and it is presumed that there are economies in scale in delivery. This price excludes VAT and gives a fuel cost of € 0.042 per kWh.

Value of heat: It is assumed that all heat is consumed onsite. As was calculated for Germany and the UK, the value of heat is based on the natural gas price available for industrial consumers, in this case € 0.0934 per kWh (EU Energy website, 2012). Using the correction factor of 0.8, this gives a value for heat of € 0.117 per kWh.

Value of electricity: Although a feed-in tariff for the specified technology is available, it corresponds to roughly € 0.10 per kWh fed into the grid (Danish Energy Agency, 2009). As the electricity cost to industrial consumers with an annual consumption of 2 GWh is € 0.1091, it is at least equally attractive from a financial perspective to consume the bulk of the electricity onsite. It is therefore assumed that all electricity is consumed onsite, and none is exported to the grid.

Corporate taxation: The Danish corporate taxation rate is fixed at 25% (Ministry of Foreign Affairs of Denmark, 2011).

Public Service Obligation: An additional tax is levied on all producers of electricity, even when the electricity is consumed onsite, although it is substantially lower in this case. This tax rate varies, but is set at € 2 per MWh of net electricity generated, increasing at the rate of inflation. For electricity which is wholly or mainly delivered to the grid, this value increases to roughly € 20 per MWh (Energinet.DK, 2012).

Depreciation: Denmark uses the reducing balance method, with a 25% rate annually on machinery and equipment (Ministry of Foreign Affairs of Denmark, 2011).

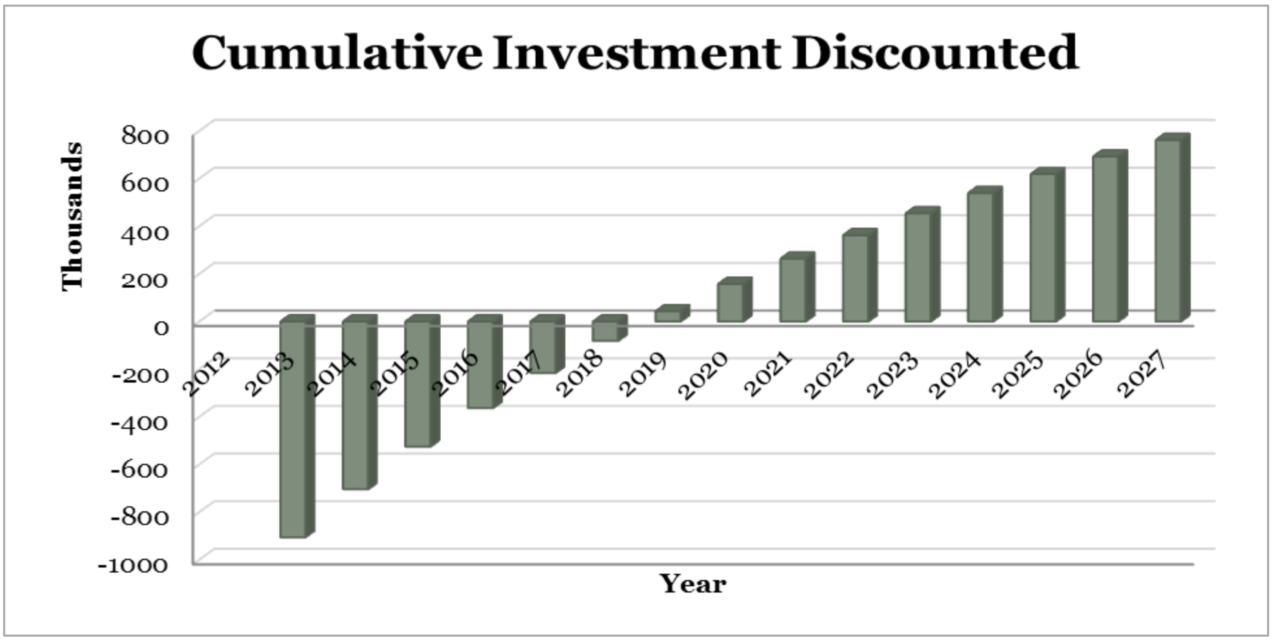
The returns from the investment are given in Table 4.8.

Table 4.8: Returns from investment in Denmark

Investment measure	Value
NPV (@10% discount rate)	€ 761,920
IRR	20.3 %
Discounted payback period	7 years

Despite the lack of subsidies, the returns from investment for the Danish case are an improvement on both the German and the UK investment scenarios. Figure 4.3 illustrates the slight improvement over the UK investment scenario and the significant improvement over the German investment scenario:

Figure 4.3: Discounted, cumulative cash flow for Denmark



The key difference between the Danish case relative to the German and UK cases is the ratio of the value between heat income and electricity income; for the Danish investment scenario, this ratio is 5:1, as opposed to the 2:1 ratios seen for Germany and the UK.

This is partially due to the choice of using (individual) natural gas CHP as a comparison scenario. In Denmark, most heating is derived from district heating networks, and the average prices tend to be lower than what the equivalent individual natural gas CHP (Tang, 2011). Natural gas prices paid by the consumer are substantially higher than in Germany or the UK, principally due to the amount of non-recoverable taxes applied to the natural gas price (Danish Energy Agency, 2012). Even with adjusting the value of heat to reflect average district heating prices in Denmark, the investment case is still positive and roughly equivalent to the UK investment case scenario without ROCs.

4.6 Discussion

This section compares the main results from the investment cases in each country and discusses key influencing factors. Table 4.9 compares the main results from each of the three investment cases. Discounted payback period is abbreviated to D.P.P.

Table 4.9: Comparison of results

Country	NPV	IRR	D.P.P.
Germany	€ 3,109	10.0 %	15 years
UK	€ 563,722	17.5 %	8 years
Denmark	€ 761,920	20.3 %	7 years

What is unusual is that while the subsidy support in Germany appears largest, the total returns from investment are lower there than in the UK and in Denmark. This is not immediately obvious, as the EEG 2012 rate of € 203/MWh electricity would appear greater than the UK ROC and LEC values of € 65.19/MWh (1.5 ROCs) and € 5.27/MWh, respectively, even when including the RHI values of € 56/MWh and € 23/MWh.

Even more unusually, Denmark has the highest returns on investment despite the fact that no subsidies were included in the cash flow. For the Danish case, the high return is primarily due to the avoided energy and CO^2 taxes due on the natural gas-based heating alternative. Exemption from taxation acts as an indirect subsidy.

Main differences

Table 4.10 illustrates where the key differences in the generated values lie. All values are reported as an average number across the investment period.

Table 4.10: Comparison of average values generated

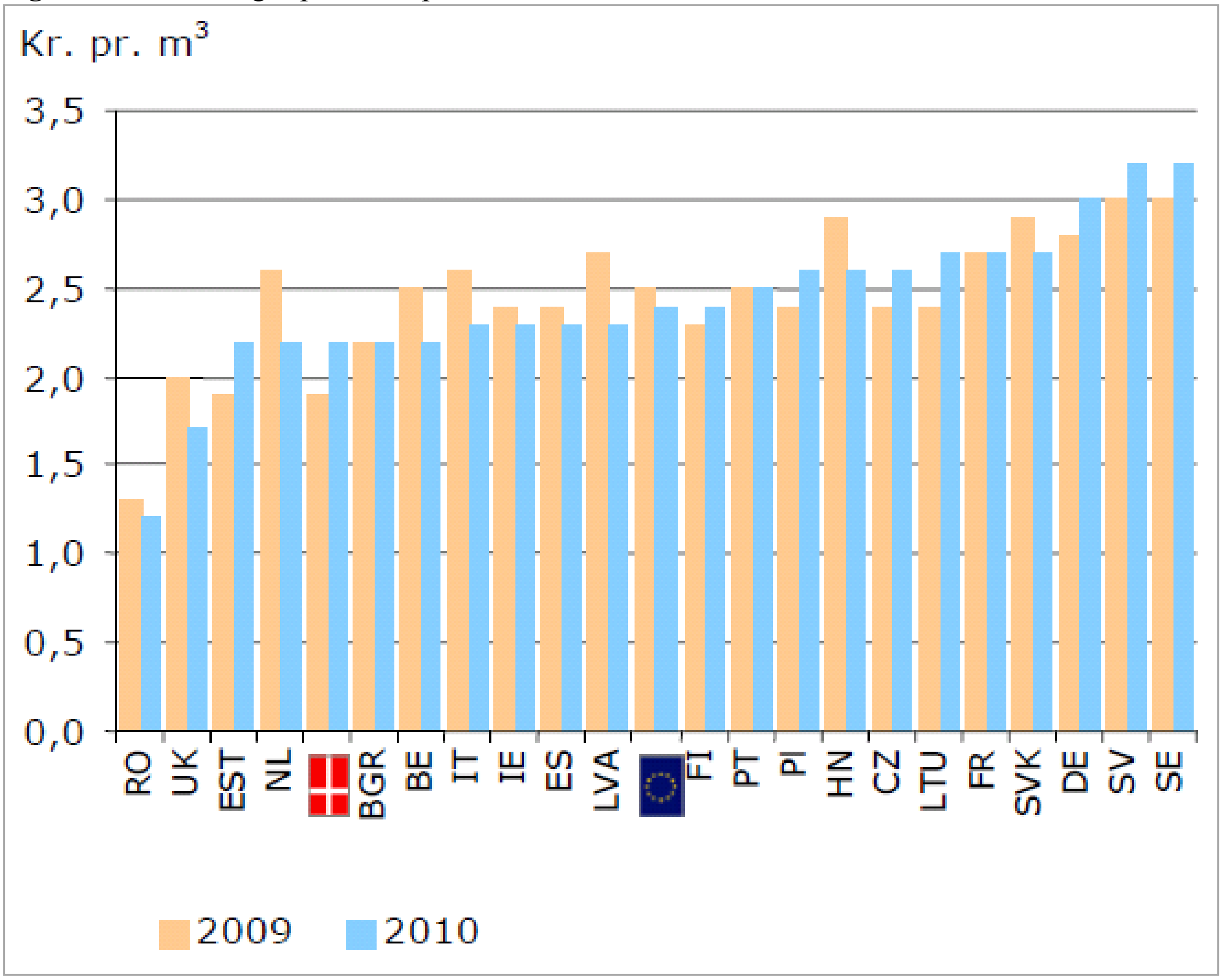
Country	Germany	UK	Denmark
Value from electricity	-	€ 120,257	€ 114,186
Value from heat	€ 309,904	€ 241,037	€ 574,307
Value from electricity subsidy	€ 170,715	€ 73,737	-
Value from heat subsidy	-	€ 142,926	-
Total value	€ 480,619	€ 577,957	€ 688,493
Subsidy proportion of income	36%	37.5%	-

The values from heat differ substantially across the countries, reflecting the differences in natural gas prices including non-recoverable taxes.

Tax exemption plays a significant role in the profitability of the Danish investment case but is not included in the table above. In order to calculate the appropriate level of tax exemption a number of additional assumption would have to be included; the identification of a close substitute technology with a fuel type which required the taxes to be paid, price projections of this fuel over time, plant efficiencies and costs to name a few. For simplicity, this analysis has been omitted.

The actual natural gas price for industrial consumers in 2009 and 2010, excluding levies and taxes, is shown in Figure 4.4 (values in DKK per cubic metre):

Figure 4.4: Natural gas price comparison across EU, nominal values



Source: Danish Energy Agency (2010)

As is illustrated in Figure 4.4, Danish natural gas prices are closer to UK values than German values once non-recoverable taxes are controlled for. If we were to take the difference between the natural gas value used for the UK investment case and the natural gas value used for the Danish investment case, the difference relative to the average total income would be roughly 48%. This value is substantially greater than the subsidy proportion of income for both the UK and Germany and explains why the investment case for Denmark exhibits such large returns, despite the decision not to apply the available feed-in tariff.

Table 4.11 illustrates where the key differences in the generated costs lie. Only the costs which vary between the countries have been included, i.e. investment costs, insurance costs and operation and maintenance costs are not shown. All values are reported as an average across the investment period.

Table 4.11: Comparison of average costs generated

Country	Germany	UK	Denmark
Fuel costs	€ 197,500	€ 209,656	€ 283,516
Total costs	€ 282,558	€ 294,714	€ 368,574
Fuel cost proportion of total costs	69.9 %	71.1 %	76.9 %
Depreciation	€ 56,667	€ 54,673	€ 55,909
Corporate tax rate	30 %	24-23 %	25 %
Corporate tax	€ 42,418	€ 52,613	€ 66,002

Note that as the other costs are the same across investment cases, fuel costs are the primary driver of the differences in the total costs.

Depreciation is not part of the cash flow of the investment project, but is used to calculate the corporate tax owed on the returns from investment. The higher the depreciation deductible from the taxable income, the lower the corporate tax paid. This helps explain why the corporate taxes paid in Germany are the lowest, despite having the highest rate.

4.7 Conclusion

Although at first glance the German EEG support seems the most favourable of the support policies in the three countries, other factors can be seen to dominate the returns from investment.

Even though Germany has the lowest fuel costs, lowest corporate tax burden (measured in paid tax rather than tax rate) and an intermediate heat value, the returns from investment for Germany are lower than those for Denmark and the UK. Given that levies and energy taxes of the sort employed by Denmark and the UK are against the federal constitution in Germany (Bürger et al., 2008) it is difficult to suggest improvements to the current national policies. German renewable energy investments are possibly best promoted at the state or regional levels, where local differences may determine which technology is most suited.

In Denmark, returns are primarily driven by the high prices on natural gas and electricity paid by consumers, which is largely a result of the tax burden. Consumption of renewable energy generated onsite is strongly favoured relative to the tax burden avoided, and as this pattern reduces transmission losses and balancing burdens on the distribution net, this approach makes sense from a public sector perspective. To what degree this taxation strategy damages industrial competitiveness is not clear from this study; however, given that the natural gas prices are roughly triple what is paid in the UK and almost double what is paid in Germany, significant consequences are unavoidable.

The UK, having a later starting point for the adoption of renewable energies in combination with ambitious targets, favours a highly aggressive policy support approach. Given very low alternate fossil-fuel sources in combination with relatively high biomass costs relative to natural gas costs, this approach appears most likely to garner public support. However, the current variety and continuous amendments and extensions to the policies available may be a source of confusion to the average investor and a lot could be gained from simplification of the policy support. As it is, the actual benefit gained from the policy support mechanisms is not immediately obvious.

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Chapter 5. Applications of a Stirling engine based woodchip fired trigeneration system in UK supermarkets

Paper status

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5.1 Abstract

On behalf of a UK-based upmarket retailer, MITIE Asset Management (Mitie) has purchased two 4-engine updraft gasification combined heat and power (CHP) plants from Stirling.DK Ltd. (SDK). The CHP plants are to be part of a trigeneration system delivering heat, electricity and cooling to provide a complete carbon-neutral energy solution for UK supermarkets. Each SDK plant will deliver 140 kWe and 500 kW of useful heating (600 kW total heating), using approx. 320 kg of fresh woodchips per hour (800 kW input), operating 6,565 hours a year. The aim of the paper is to provide an overview of technical and economic benefits of utilizing biofuelled trigeneration systems in the retail sector. We expect that the largest gains will come from the utilization of heat in an absorption/adsorption chilling system to substitute cooling from electricity. To the authors' knowledge, there have been no previous applications of small-scale solid biofuel combustion systems for trigeneration in the retail sector. These two cases should provide valuable information on the commercial viability of small-scale biofuel systems.

5.2 Introduction

While there are biomass-based technologies available which generate carbon-neutral heat and power, these technologies are typically large, with fuel inputs above 1-2 MW. The most common technology available is steam turbine plants, but alternatives such as organic rankine cycle (ORC) generators and gas engines with biomass gasification have also entered the market.

The complexity of these systems makes them prohibitively expensive to scale down for onsite generation. This dilemma, in combination with the increasing demand for generating and consuming energy from onsite production, highlights a technology gap in the market.

The Stirling engine is uniquely suited for biomass-based small-scale applications. The advantage of the Stirling engine over an internal combustion engine is that the heat is not supplied to the cycle by combustion of the fuel inside the cylinder. Instead, the fuel is combusted in a combustion chamber, and the heat is supplied to the engine through a heat exchanger. This allows the utilization of variable heat sources, capable in delivering a flue gas (or waste heat stream) of more than 1.100°C (Marinitsch, 2011). The external combustion makes the application for woodchips and other bio-fuels obvious, and in the range of electric power output up to 300 kWe, Stirling engines are an attractive technology for carbon-neutral combined heat and power generation (CHP) from bioenergy (Carlsen, 2005).

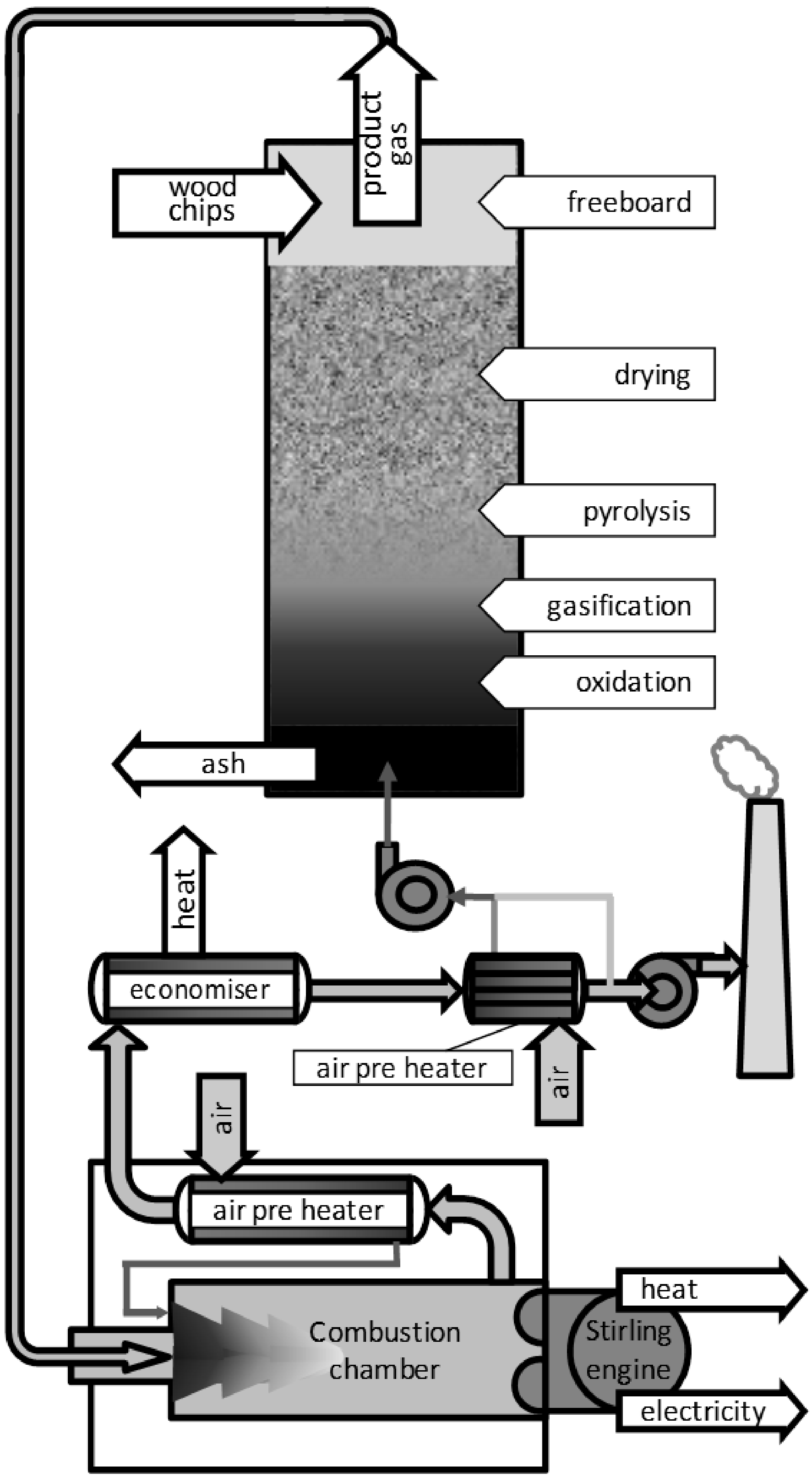
On behalf of a UK-based retailer, MITIE Group PLC has invested in two Stirling engine CHP plants to be used in conjunction with an adsorption chiller at one site and an absorption chiller at an alternate site, sized to provide heat, power and cooling to meet the needs of two supermarkets. The Stirling engine plants are manufactured by Stirling.DK Ltd. (SDK). As far as the authors are aware, this is the first attempt at installing an onsite biomass trigeneration energy solution explicitly sized according to the demand profile.

The purpose of this paper is to describe and assess the two energy solutions relative to the site requirements. The paper is organized as follows; Section 5.3 describes the Stirling engine CHP plant. Section 5.4 provides information on the other site specifics, including integration of the chiller units. Section 5.5 provides a market overview of UK-specific factors relating to support and development of onsite renewable energy options. Section 5.6 provides an assessment of the technology, in terms of performance and financing. Section 5.7 concludes.

5.3 Technology description

The Stirling engine CHP plant consists of three main parts, the updraft gasifier, the combustion chamber and the Stirling engine, as well as auxiliaries such as the economizer, gasification air pre-heater and blowers. Figure 5.1 shows a flow diagram of a typical Stirling engine CHP plant.

Figure 5.1 Flow diagram of a Stirling engine CHP plant using updraft gasification (1-engine plant) (Marinitsch, 2011b)



Fresh woodchips are fed into the top of the gasifier and the product gas emitted moves counter to the biomass. That is, the product gas streams upwards (updraft) as the biomass moves slowly downwards. During the thermal conversion of biomass in the gasifier, four different zones have to be passed; drying, pyrolysis, gasification and oxidation, until the biomass is converted to ash and reaches the bottom of the gasifier.

The first zone, at the top of the gasifier, dries the woodchips. The drying is followed by a continuous heating of the woodchips and will lead to a start of the pyrolysis process, regarded as the second zone. Pyrolysis is a thermal conversion in an oxygen-free environment which releases volatile gases, including steam and tar. The remaining non-volatiles in the biomass are converted to char, which mainly consists of carbon.

The third zone is the gasification zone. The char reacts with a gasification agent and creates a gas mainly consisting of carbon monoxide, carbon dioxide, methane and hydrogen. The final zone is the oxidation zone, which is located below the gasification zone. In this zone, the remaining charcoal is combusted to ash with the oxygen supplied from the gasification agent.

Typically, air, carbon dioxide or steam is used as a gasification agent. In this particular gasifier a slightly preheated mixture of air and flue gas is used. The mixture contains carbon dioxide as well as water vapour. The oxidation process at the bottom creates all the necessary heat for the upstream processes in the above zones.

The ash is removed from the bottom of the gasifier using a scraper system and a screw conveyor. The product gas from an updraft gasification process contains significant amounts of tar compared to product gases from other gasification processes.

The net calorific value is typically in the range of 5-6 MJ/kg on dry basis or roughly 10% of the heating value of natural gas. The temperature at the very top of the gasifier is around 75°C (the dew point of the product gas), kept stable by the equilibrium between the vaporized water from the fresh woodchips and the condensed water from the product gas (Marinitsch, 2011).

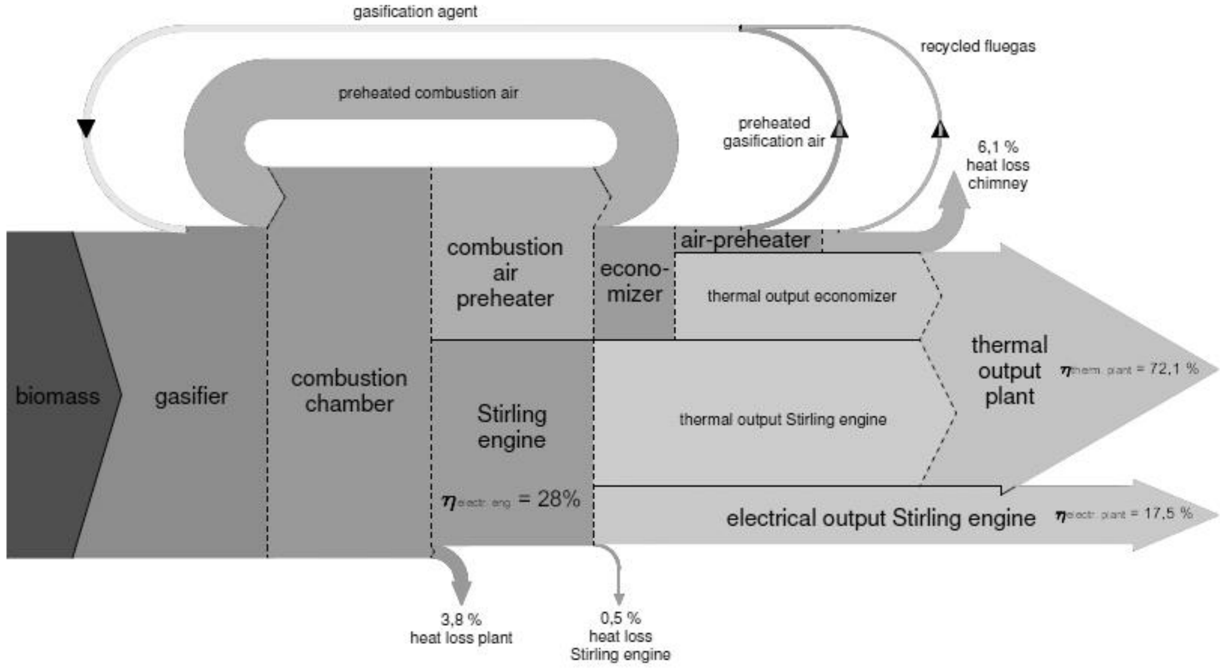
In the space directly above the woodchips, there is a slight under-pressure, which is generated by the flue gas blower at one end of the plant. This pressure sucks the product gas into the combustion chamber and the product gas burner. The product gas burner is specifically designed for the product gas combustion, which contains high amounts of tar, and for the utilization of preheated air. This unique design ensures high-quality combustion and low emissions. As the tar is fully combusted in the combustion chamber, it has no negative impact on the Stirling engine. Consequently, no product gas cleaning, tar removal or gas conditioning devices are needed.

The Stirling engine is mounted opposite the burner in the other end of the combustion chamber. The Stirling engine heater transfers 125 kW of heat from radiation and convection to the engine internal work gas. This results in a nominal electrical power output of 35 kWe and in a net electrical engine efficiency of 28%. The heat not converted into mechanical energy and subsequently into electricity amounts to 89 kW. This heat is transferred to the cooling water in the Stirling engine cooler at 25°C-75°C, depending on the temperature of the cooling water circuit. In addition, there is a radiation loss of around 1 kW from the engine crank case.

The Stirling engine itself has four cylinders arranged in a square, with the cylinder axes parallel to each other. The asynchronous generator has 6 poles and it is located inside the pressurized crank case. Helium is used as working gas at a mean pressure of 4.6 MPa. The heater sections in typical Stirling engines have narrow spaces, but these have been enlarged in order to adapt the system to the demands for different fuels in various applications, such as in direct combustion of solid biomass. In general, the risk of deposit formation in biomass combustion processes is mainly due to aerosol formation and condensation of ash vapours when the flue gas gets cooled (Marinitsch, 2005).

The flow of the flue gas through the plant takes it directly by the end of the combustion chamber where it passes the Stirling engine heater. The Stirling engine heater reduces the flue gas temperature from around 1,350°C to around 650-750°C. The flue gas then flows through the combustion air preheater integrated in the combustion chamber. There, the air is in counter flow to the flue gas, which optimizes the heat utilization and allows a high air preheating temperature to be reached. Consequently, the flue gas is cooled down to around 450-500°C, while the air is heated up to around 450°C. After leaving the combustion chamber, the flue gas enters an economizer where it is cooled down to around 150°C, corresponding to a thermal power output of around 50-60 kW. A part of the remaining energy in the flue gas is used in an air preheater that is preheating the air that mixed with a recycle of flue gas to the gasification agent. The remainder of the flue gas, with a temperature of around 120-140°C, is sucked through a flue gas suction blower and exits through the chimney at the end of the plant.

Figure 5.2 Energy flow chart of Stirling engine plant



Source: www.stirling.com

The energy flow through the plant is shown in the energy flow chart in Figure 5.2. The figure shows the biomass input as 100%, corresponding to a fuel input of 200 kW.

5.4 Scheme design

Both sites use a 4-engine Stirling woodchip plant. The electrical output is fed to the store and is used to offset the import of mains electricity. The heat from the SDK plant feeds a primary header and from the header separate pumped circuits feed the following demands;

- Store primary heating demand
- Store primary hot water demand
- District heating demands
- Adsorption / absorption chiller primary demands

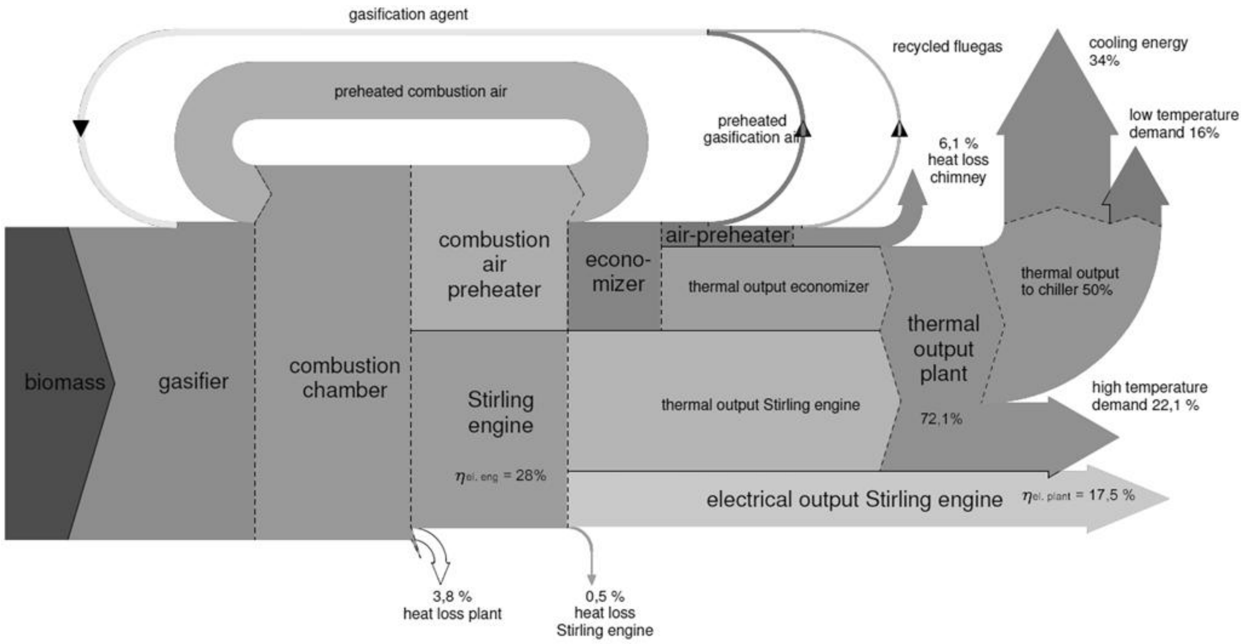
The two solutions built to date differ in the detail of their primary heat use which has influenced the choice of cooling technology.

The first site uses a primary design water condition of 83°C flow and 60°C return. The 83°C water feeds a plate heat exchanger which in turn supplies heat to a buffer vessel that feeds the adsorption chiller. The chiller supplies water at 10°C to the water cooled refrigeration cabinets in the store. The use of 10°C water displaces the nominal 16°C water that would be supplied by the electric chiller. The lower water temperature reduces the power demand of the cabinet compressors. Once the plant has been running for an agreed time period, the intention will be to lower the chilled water temperature further, thereby increasing the thermal demand and reducing the electrical demand.

The second installation uses a 90/60 water temperature circuit and a conventional absorption chiller, but the integration with the water cooled cabinets is similar.

The hot water that is returned to the header from the chiller and heating and hot water demands is then supplied directly back to the SDK plant. If the return temperature is above 60°C then the surplus heat is dumped via a dry cooler. Figure 5.3 shows the energy flow of the trigeneration plant.

Figure 5.3 Energy flow chart of trigeneration plant



The adsorption chiller was supplied by Weatherite (model ADCM1-145) and the absorption unit by Broad (model BDHY30).

The nominal output of the plant is shown in Table 5.1. Values in brackets are for the second site.

Table 5.1 Nominal capacity of trigeneration plant

Capacity (kW)	**Daytime**
Electricity	35
Heat	560
Chiller	270 (232)

Roughly 60 kW of the heat produced from the plant is of too low thermal value to be of use, so the useful heat capacity of the plant is 500 kW rather than 560 kW.

5.5 UK retail energy consumption

The UK has one of the most aggressive strategies for promoting renewable energy generation in the EU. A wide range of incentives and penalties are in place to promote renewable energy uptake, including tax relief and additional taxes, use obligations for onsite generation and tariffs for both heat and electricity from renewable resources.

Superstores, defined as supermarkets with between 1,400 m2 and 5,000 m2 sales areas, have an average annual energy consumption beginning with 600 kWh/m2 annually and increasing to 1,000 kWh/m2 year in inverse proportion to store size (Tassau et al., 2011).

More than 70% of the energy consumed is in the form of electricity, particularly refrigeration and lighting, which contribute to over half of all electricity consumed. Other electricity consumption is due to ventilation and air conditioning, baking and other services. The remainder of the energy consumed is primarily in the form of heating and hot water. Heating and hot water requirements are normally generated using gas-fired boilers.

Typically supermarkets use fluorescent lighting both inside and for outdoor display. Exchanging fluorescent tubes with LED lighting can reduce power consumption with app. 50-80%, with no corresponding loss in light intensity (lumen) or control.

Refrigeration is usually delivered via vapour compression chillers, which deliver all the cooling required by the refrigerated display cabinets, cold rooms and air conditioning systems. Substituting electrical chillers with adsorption or absorption chiller units shifts energy consumption from electricity to heating, which both reduces costs and increases efficiency.

Trigeneration systems with cooling as well as heating and electricity are ideally suited for the annual energy demand in a typical supermarket. The heat demand for space heating is primarily seasonal, with higher demands corresponding to a fall in outside temperatures. The cooling demand for refrigeration is relatively constant throughout the year and a CHP system sized for the refrigeration requirements of a supermarket would ensure a high and continuous load factor of the energy plant. One unit of heating, converted using chiller technology, roughly corresponds to 0.7 units of cooling. In this manner a substantial part of the electrical consumption of a supermarket can be converted into heat demand, which all other factors being equal is both easier and cheaper to produce.

Support for renewable energy in the UK

The support mechanisms for renewable energy in the UK can be divided into two categories; “carrot” and “stick”. Carrot mechanisms are incentives that provide financial compensation for investments into renewable energy technologies. Stick mechanisms are legally binding requirements which create penalties, for example a refusal of planning permission grants or an additional tax.

Altogether, four different carrot mechanisms have been identified for the identified onsite biomass technology:

- Renewable Obligation Certificates (ROCs)
- Renewable Heat Incentive (RHI)
- Enhanced Capital Allowance (ECA)
- Levy Exemption Certificates (LECs)

ROCs are certificates issued to accredited generators for eligible renewable electricity generated within the UK and supplied to customers within the UK by a licensed electricity supplier. One to two ROC(s) are issued for each megawatt hour (MWh) of eligible renewable output generated (Ofgem, 2012).

The RHI is a new tariff system introduced in 2011, payable to energy users generating their own heat from renewable sources. The tariff is payable per MWh of metered ‘useful’ heat generated on site. Currently, the scheme is only applicable to commercial owners, but it is expected to be expanded to private individuals in 2013 (DECC, 2012).

The ECA allows the full cost of an investment in a designated energy-saving plant and machinery to be written off against the taxable profits, in the period in which the investment is made. This is particularly useful for commercial operators, as the write-off can be subtracted from the company's annual taxable profit, rather than just the plant-specific profits (EHA, 2012). The ECA is not considered explicitly in the investment case in section 5.6 as it is assumed that the investment is made a year prior to the first profits earned on the plant. The supermarkets in question would however be able to write off profits earned from the store the year of the investment.

LECs are exemptions from a tax on energy delivered to non-domestic users in the United Kingdom aimed at providing an incentive to increase energy efficiency and to reduce carbon emissions. The exemption applies to high-quality CHP generation. Profits from the levy are administered in a fund and redirected to promote renewable energy initiatives (Ofgem, 2012b).

CHP plants in the UK should conform to the quality assurance standards set out by the Combined Heat and Power Quality Assurance (CHPQA) program in order to qualify for ECAs and apply for LECs. For biomass CHP plants, this includes a minimum electrical efficiency of 10%, relative to fossil fuel CHP which requires a minimum electrical efficiency of 20%.

In addition to these general conditions, UK retail suppliers are required to build new supermarkets in accordance with the building code regulations L2A, which require emission reductions of 25% relative to the 2006 level (a "stick" mechanism).

These building regulations were in turn inspired by the "Merton" or "Merton-plus" rule, legislation at local planning authority level which requires a share of energy consumption in all new buildings to come from onsite renewable energy generation. This legislation was supported at national level in the Planning Policy Statements 1 and 22, but has now been superseded by the building code regulations.

The original share was 10% renewable energy onsite generation in all buildings of more than 1,000 square meters or in residential dwellings with more than 10 units. Local planning authorities are still able to insist that conformity with the building code regulations includes a share of onsite renewable energy generation, typically 10 or 20%.

5.6 Assessment

This section provides a brief overview of the standard assumptions and methodology used in the investment cases, followed by the returns to investment. Note that the investment assumptions are not the reported real costs, as this would violate confidentiality; instead, estimates are given which reflect real costs from several plants. As the investment returns from the second site closely mirrored the results from the first site, only the first investment results are reported.

The aim of the analysis is to estimate whether the above-mentioned support mechanisms are sufficient in supporting private investment into renewable trigeneration systems, by savings from energy efficiency and energy support mechanisms following the ‘carrot’ incentives outlined above, or whether supermarkets would increasingly turn to such systems mainly because of the ‘stick’ approach. As such the returns to the two systems are estimated including income streams from the mentioned support mechanisms and evaluated against a hurdle rate indicative of reasonable returns to investment from the viewpoint of the supermarket.

General assumptions and methodology

All values are reported in Euro. For values originally in Pounds Sterling, a conversion rate of EUR 1.2 to the Pound was assumed.

Technical data on the plant is taken as given from the equipment supplier. Estimates on total installed costs and annual service costs are likewise taken as given. These cost assumptions include estimates of installation costs, transport costs and operating costs of the supplier of the equipment/plant owner. Land cost is not included.

For confidentiality reasons, the exact specified investment costs are not reported in this paper. A rough investment estimate is given, based on current 2012 costs. Likewise an overall estimate of the annual service costs (operation costs) is given.

All prices are in nominal values; i.e. indexed to predicted inflation increases. The UK Treasury GDP deflators from December 2010 have been used for all three countries. The deflator is set 2.7% from 2015 onwards.

Table 5.3 gives the technical characteristics of the plant considered (as given by the equipment supplier).

Table 5.3: Technical characteristics of base case technology

Characteristic	Efficiency	Effect
Input	-	800 kW
Overall output	88%	704 kW
Heat output	70.5 %	564 kW
Electrical output	17.5%	140 kW
Own electrical consumption	-	20 kW
Net electrical output	15%	120 kW

The plant is assumed to have an availability of 74%, equivalent to roughly 6,500 hours, operating at full load.

Table 5.4 gives the financial characteristics of the investment. The annual service cost reflects the value in 2013, i.e. including one year's worth of inflation. The total investment cost includes equipment costs, transport, installation and building requirements but not value-added tax. A conservative estimate of a scrap value equal to nil has been set.

Table 5.4: Financial characteristics of the trigeneration plant

Characteristic	Value
Lifetime	15 years
Annual Service Cost (2013-value)	€ 57,809
Total Investment Cost (2012-value)	€ 2,750,000
Scrap Value	€ 0

Income, for example from the receipt of subsidies, is assumed to be paid in full in the year of generation.

Taxes are paid on the EBITA (earnings before interest, taxes and amortization).

It is assumed that the investment is fully financed through a low-interest public loan with a net interest rate of 8.5%. This gives an overall rate of 6%. Interest payments are not included in the cash flow, but rather through the discount rate in the net present value (NPV) calculations. This discount rate is equivalent to a company's weighted average cost of capital (WACC) or minimum attractive rate of return (MARR) on an investment.

The NPV and IRR are used to calculate the returns to investment:

Solving for NPV, such that an investment made at time t=0 (I_0) is subtracted from the sum of the future net benefits (*NB*) over an investment's lifetime (*t=0,...,n*), each of which is weighted by the discount rate (*r*) at time *t=n*;

$$NPV = -I_0 + \frac{NB_1}{(1+r)^1} + \frac{NB_2}{(1+r)^2} + \ldots + \frac{NB_n}{(1+r)^n} = -I_0 + \sum_{t=1}^{n} \frac{NB_t}{(1+r)^t}$$

The NPV is expressed in a given currency and is stated in absolute terms. The discount rate is expressed as a constant percentage. The accept/reject decision for an option requires a positive NPV, i.e. an NPV value greater than zero.

Solving for the IRR, *r*, such that an investment (*I*) made in the current time period (*t=0*) is equal to the sum of future net benefits (NB) over the lifetime of the investment:

$$I_0 = \frac{NB_1}{(1+r)^1} + \frac{NB_2}{(1+r)^2} + \ldots + \frac{NB_n}{(1+r)^n} = \sum_{t=1}^{n} \frac{NB_t}{(1+r)^t}$$

The IRR is expressed as a percentage and measures the benefits of a given investment relative to its initial outlay (or the costs relative to an initial payout). The accept/reject decision of a given investment must be compared to the identified hurdle rate. If a given investment proposal results in an IRR greater than the hurdle rate, the proposal is judged profitable.

The results from the respective investment cases are reported as a NPV, a discounted payback period and an internal rate of return (IRR). Only investments with a positive NPV, a discounted payback period less than the investment lifetime and an IRR higher than the discount rate are considered worthwhile.

Other investment assumptions

Fuel cost: Fuel cost is based on the local biomass agreements. A price of £65/ton is assumed, for woodchips with a moisture content of 30%, giving a fuel cost of € 0.022 per kWh.

Value of heat: It is assumed that most of the heat is consumed onsite. Roughly half the heat produced is converted into cooling, at a coefficient of performance of approx. 0.7.

As natural gas CHP plants were identified as a possible substitute for the SDK CHP plant, the natural gas price is used as a base value to calculate the value for heat. A natural gas price of € 0.0392 is taken from the European Commission's Energy Portal. This value is from November 2011 and as reported for industrial consumers who consume 0.25 GWh of natural gas annually. The price includes the wholesale price, transmission, distribution and administration costs and non-recoverable taxes (i.e. VAT is not included) (EC, 2012).

The value is then divided by a factor of 0.8 in order to correct for some generation costs and conversion losses. This gives a value for heat of € 0.049.

Value of electricity: A similar approach is followed for electricity. It is assumed that all electricity is consumed onsite. The stated value for electricity on the Energy Portal for industrial consumers using 2 GWh/year is € 0.1149 (EC, 2012). No correction factor is applied.

Corporate taxation: The corporate taxation level is currently at 24%, but is predicted to decrease to 23% in 2013 and from then onwards (HM Treasury, 2012).

Depreciation: In the UK, it is recommended that capital investments are depreciated using the reducing balance method at a rate of 20% per year (Worldwide tax rates, 2012). Only the original capital equipment is depreciated.

Income from subsidies: There are three separate income sources from subsidies accounted for in this investment scenario. All subsidies increase with inflation.

ROCs: renewable obligation certificates are issued to the supplier per MWh renewable electricity generated and redeemed at market prices. For simplicity, a value for 1 ROC is set equal to £ 40.69 (~€ 48.8) (DECC, 2011). Dedicated biomass plants with CHP are eligible for 2 ROCs per MWh electricity generated or 1.5 ROCs in combination with the RHI subsidy. For this investment case, it is assumed that 1.5 ROCs are given. The value of the ROCs is discounted to 89% of their value in order to take into account power purchase agreement (PPA) costs. This value sums to € 65.19 per net MWh generated.

LECs: levy exemption certificates also vary over time but are assumed to have a base value of £ 4.72 (~ € 5.66) per MWh. The value of the LECs is discounted to 93%to reflect PPA costs. (DECC, 2011) This sums to € 5.27 per net MWh generated.

RHI: Solid biomass CHP with a thermal output between 200 kW and 1,000 kW qualifies for £ 47 (~

€ 56) per MWh for the first 1,314 hours of full-load operation and £ 19 (~ € 23) per MWh for the remainder (DECC, 2011b). No discounting is applied, as it is uncertain whether something similar to the PPA would apply.

The returns from the investment are given in Table 5.5.

Table 5.2: Returns from Investment

Investment measure	Value
NPV (@6% discount rate)	€ 210,471
IRR	7 %
Discounted payback period	14 years

5.7 Conclusion

For a heat-based generation system such as the SDK plant, optimal heat usage is a key factor in making the economics of the plant work. Although it was initially expected that the largest gains from investment would come from the conversion of heat into chilling, this was not the case. However, there is scope for increased usage of the heat and improved conversion to chilling, which in the longer term will improve the economics of the plant.

From the investor's viewpoint, the decision to implement a high-cost solution that will satisfy final planning permission requirements in 2017 allows for movements up the learning curve. The alternative, which would be to install the absolute minimum requirements necessary to achieve planning permission, requires that the contractors familiarize themselves with increasingly complex technologies almost with each construction. This would substantially reduce the potential for improvements from the original design, as a new design would be required each time.

While the investment is financially viable and technically feasible, there is scope for further improvement. Key factors influencing the economics of installing a biomass-based trigeneration plant are:

- efficient transformation of heat into cooling to displace electricity consumption
- sizing to avoid excess heat production
- service costs
- fuel costs

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Chapter 6. Prices of agricultural commodities, biofuels and fossil fuels in long-run relationships – a comparative study for the USA and Europe

6.1 Paper status

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6.2 Abstract

Time-series data for the USA and Europe representing prices of agricultural commodities, biofuels and fossil fuels are used for a comparative analysis of long-run price relationships. There is some evidence for cointegration between ethanol and gasoline, especially for the USA, and in the case of biodiesel stronger evidence of cointegration between biodiesel, diesel and soya oil for both the USA and Europe. Finally, biofuel prices do not seem to influence agricultural commodity prices, or fossil fuel prices.

6.3 Introduction

Due to increasing environmental concerns the production and use of biofuels, i.e. biological oils for transportation purposes, has been stimulated during the later years. The United States of America (USA) and the European Union (EU) both provide policy support for the production of biofuels; the European Commission (2012) requiring member states to achieve a minimum 10% target for the share of renewables in transport by 2020, while the US Energy Independence and Security Act of 2007 extended the Renewable Fuel Standard, requiring a substantial increase in the total amount of biofuels added to gasoline by 2022.

Historically, agricultural products have not been directly related to traditional transport energy consumption since the use of horses and other livestock were superseded by steam engines and the invention of the automobile. They are now increasingly becoming integrated in the energy sector once again, through the uptake of bioethanol and biodiesel. In light of this renewed connection between agricultural feedstock and transport, a relevant topic for investigation is whether the prices of agricultural oils have been – or will be – influenced by the prices of fossil fuels as they become increasingly closer substitutes in relation to energy demand. In the case where some of the agricultural oils are reasonable substitutes for fossil fuel products, e.g. rapeseed oil used in a mixture with diesel oil, some influences or co-movements must be expected between the various fuel prices and a core question is to ascertain the direction of causality. Another implication is that with increases in future fossil fuel prices it may be naive to expect the prices of biofuels to remain relatively low or stable. These issues of price links and causality have been addressed in a number of studies during the recent years but with no general consensus in the empirical findings.

We expect causality from fossil fuels to biofuels as the biofuel market is still a relatively small part of the total transport fuel market in the EU and the USA (OECD-FAO, 2013), making it unreasonable to expect price changes in biofuels are driving major price changes in fossil fuels – although this may change in the future. The relationship between biofuels and agricultural oils is slightly less clear and there might be bi-directional causality. Agricultural oils are a principal component of biofuels, so price changes in the feedstock could drive price changes in biofuels, depending on the proportion of agricultural oils used relative to fossil fuels. On the other hand, e.g. the OECD and FAO consider increasing demand for biofuels as a driver for increasing agricultural oil prices (OECD-FAO, 2013). Finally, causality might be from fossil fuels to agricultural oils, as they not only impact transport energy costs but also fertilizer costs.

In order to empirically investigate these issues, a data set of the prices of the major substitutable agricultural oils and biofuels has been collected and will be analysed with respect to the prices of fossil fuels. The data covers both the USA and Europe with a main purpose also to make a comparative analysis for these regions of a global energy market. Most of the available agricultural oil price data go back to the first part of the 1990's and are reported as daily data (source: *Datastream*), with fossil fuels prices also available for the same time period. With daily data the number of observations is huge, but the more important dimension concerning the empirical analysis involving cointegration analysis is the absolute time span of the data set. Unfortunately, the data for the biofuel derivatives biodiesel and ethanol are only available for a shorter time span of few years. This paper will therefore only be investigating relations for this shorter time span as the purpose is to investigate co-movements for the biofuels (ethanol, biodiesel) in connection with the fossil fuels (gasoline, diesel) and the agricultural oils (corn, soya). Thus, a vital part of the present analysis is to consider all three 'levels' of prices, i.e. the price of agricultural feed stocks, biofuels and fossil fuels, in order to consistently test for co-movements among these. Part 2 presents a short literature review, part 3 is about the data sources and graphical presentations of the data. In part 4 the econometric methodology is discussed and with the empirical test results appearing in part 5. Finally, part 6 concludes.

6.4 Literature review

By now, there exist a number of empirical studies from recent years addressing the question of co-movements between the biofuel and fossil fuel prices, and with various answers to this question.

Some of the studies rely on a relatively short time dimension in the data set used, obviously caused by the before-mentioned lack of log time-series data for especially biofuels. This might cause uncertainty in relation to the reported results and has to be considered when interpreting the empirical findings which in most of the studies include unit root tests and cointegration analysis.

Most of the literature on agricultural commodities and fuels relate to the USA and include data from here, but there are also a small number of studies related to the European countries. Additional to the geographic dimension of the studies it is also relevant to distinguish between vegetable oils and biodiesel versus ethanol production as these may be seen as distinct products.

Currently most of the ethanol produced in the USA is also consumed in the USA while biodiesel is the dominant biofuel in the EU. Production of ethanol is concentrated in the USA and in Brazil, while biodiesel is produced in the EU and otherwise imported from Latin America and Indonesia (IEA, 2012). Approximately 37% of the USA's annual corn production was used in ethanol production in 2010 (McPhail et al., 2012), which is similar to the share of EU vegetable oils (primarily rapeseed) used in biodiesel production (European Commission, 2012b). Given these high shares of feedstock, there should be a clear connection in the price movements between the biofuel of choice and the feedstock of choice.

It is believed that the food crisis in 2008 was partially caused by the increase in biofuel production, especially since energy feedstock for first generation biofuel competes directly with food production (Timilsina et al., 2011). The cost drivers of biofuel are mainly feedstock, technology, land and climate (IEA, 2012). Biofuel feedstock costs are partially driven by fossil oil price increases, as these are a major component of the fertiliser used in feedstock production and therefore costs (Hertel & Beckman, 2011). Higher oil costs in turn increase demand for biofuel to the extent that they are substitutable.

The influence of biofuel on the biofuel feedstock prices is less clear-cut. A study of the drivers of corn price increases in the USA suggests that ethanol demand was the least important out of five shocks in the corn market in the time frame considered (McPhail et al., 2012). Babcock (2011) finds that while ethanol subsidies had little impact on crop prices between 2005 and 2009, the market-driven expansion of ethanol had some impact. According to de Gorter & Just (2010), studies of biofuel policies may understate the true impact when they ignore the by-products of biofuel production such as animal feed. In the USA, animal feed by-products may be as much as 30% of the corn used in ethanol production. Ethanol production does therefore not displace alternate corn uses in a 1:1 ratio. In this paper agricultural oils rather than initial feedstock are considered, and it is assumed that the by-products of biofuel production are the same as the by-products of agricultural oil production, so the by-products have been controlled for in this paper.

In terms of biofuel policies, the effects are distinct according to geographical region. For the USA, the ethanol market is influenced by three specific policies: the Renewable Fuel Standard, adopted in 2005 and extended in 2007; the removal of ethanol import tariffs in 2011, and the approval to increase ethanol blending from 10% to 15% in 2012. For the EU as a whole, the main policy consideration is the Renewable Energy Directive in 2009, which requires 10% of road transport fuel demand to be met by renewable fuels (IEA, 2012). This policy may be subject to change, as a discussion to cap first-generation biofuels at a 5% share of renewables is currently underway (European Commission, 2012b).

Relationships between corn, ethanol and gasoline in the USA have been analysed in a number of studies, and with somewhat differing conclusions. Du & Hayes (2009) find from US data 1995-2008 that the expansion of ethanol production has influenced gasoline prices in a downward direction. The study by McPhail (2011) is somewhat in line with the before-mentioned result as one of the conclusions from a structural VAR model is that policy-driven ethanol demand expansion leads to declining oil prices. These results for a regional market for biofuels influencing globally determined oil prices seem surprising, but in Du & Hayes, op. cit., the effects are restricted to US gasoline prices. Using data for 1990 to 2008, Serra et al. (2008) find strong links between corn and energy markets, and with the transmission effects working through the ethanol market. The expansion in the ethanol market is also related to the increases in corn prices in the later years, but also links in the opposite direction, i.e. from corn to ethanol, is found. This is somewhat similar to Saghaian (2010) finding strong correlation between agricultural prices and oil, and Granger causality tests significant for oil prices causing corn prices. Likewise, Du & McPhail (2012) find more close relations between corn and ethanol for the recent years. Another aspect of the price linkages between agricultural products and energy markets is the question of volatility, where Trujillo-Barrera et al. (2012) find volatility from the corn market to the ethanol market – but not in the opposite direction. Thus, the various studies of US ethanol find linkages between corn, ethanol and energy (gasoline), but with differing results in relation to the direction of influence among the specific markets.

Biodiesel is the major biofuel used in Europe and with Germany as the largest market. A few studies address the linkages between vegetable oils like rapeseed and soybean, biodiesel and mineral diesel. In relation to European countries, Peri & Baldi (2010) rely on time series data for 2005-07, testing for a cointegration relationship between rapeseed oil and diesel. They find a threshold cointegration model to hold for rapeseed oil and diesel, and it's the price of rapeseed oil that adjusts towards equilibrium determined by diesel prices, and not vice versa. In Peri & Baldi (2013) somewhat similar results appear, i.e. cointegration between rapeseed oil and diesel in specific time periods, using a methodology allowing for structural breaks and rolling cointegration. Price dynamics among rapeseed oil, biodiesel and diesel are also analyzed in Busse et al. (2012) finding varying price adjustments in time-specific regimes, with shifting orientation of biodiesel prices towards rapeseed oil and diesel prices, respectively.

As demonstrated in Sorda et al. (2010) the expansion of biofuel production during the last decade is very much associated with governmental policies, including support programs in form of blending targets and various subsidies. The use of agricultural feedstock as corn, sugar and oily seeds as inputs in the production of biofuels may even have negative effects on food prices, i.e. increasing food prices to the consumers, without contributing at all to reduce greenhouse gas emissions, *op. cit*. Therefore, the most recent initiatives from both the USA and the EU try to address these more critical issues in order to re-direct the biofuel policies in more sustainable directions, cf. the European Commission (2010, 2012, 2012b).

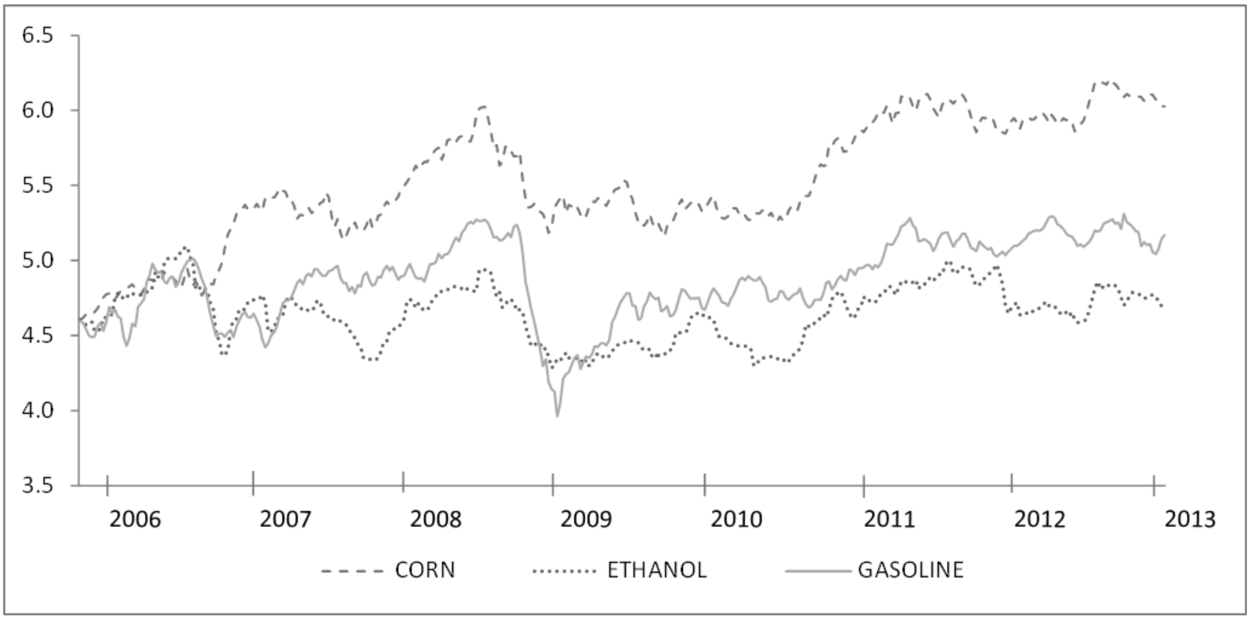
The relationships between agricultural commodities and energy have been analyzed in Ciaian & Kancs (2011a, 2011b) using data for 1994 to 2008, and with a conclusion of interdependency between crude oil prices and prices of food commodities. Likewise, Nazlioglu & Soytas (2012) find world oil prices impact agricultural prices, but in Nazlioglu (2011) only in the case of a non-linear modelling methodology is feedback between oil and agricultural prices found. In contrast to the before-mentioned studies Zhang et al. (2010) claims no direct long-run price relationships between fuel and agricultural commodities. In line with this the conclusions from Natanelov et al. (2011) are very cautious about dependence between the prices of crude oil futures and a range of agricultural commodities, using panel cointegration analysis and monthly data 1980-2010. Co-movements in prices are considered a dynamic concept, where policy interventions, economics crisis and other factor influence and complicate the price dynamics of crude oil and agricultural commodities. In contrast with previous studies Serra et al. (2011) find strong links between energy and food prices for the US, and with the link working through the ethanol market.

Thus, there seems to be some empirical evidence of price dependencies among agricultural feed stocks, biofuels and fossil fuels, although the conclusions from the literature are somewhat mixed. The use of different methodologies as well as varying time spans of the data included will obviously lead to a range of conclusions which are not consistent across comparisons. There seems to be no consensus as to which direction causality flows, or even whether a negative or a positive relationship exists between the different pairings of the three products. As stated in part 1, the following analysis will try to focus on a consistent test procedure in order to produce new insights on the price dynamics of biofuels.

6.5 Data and statistical sources

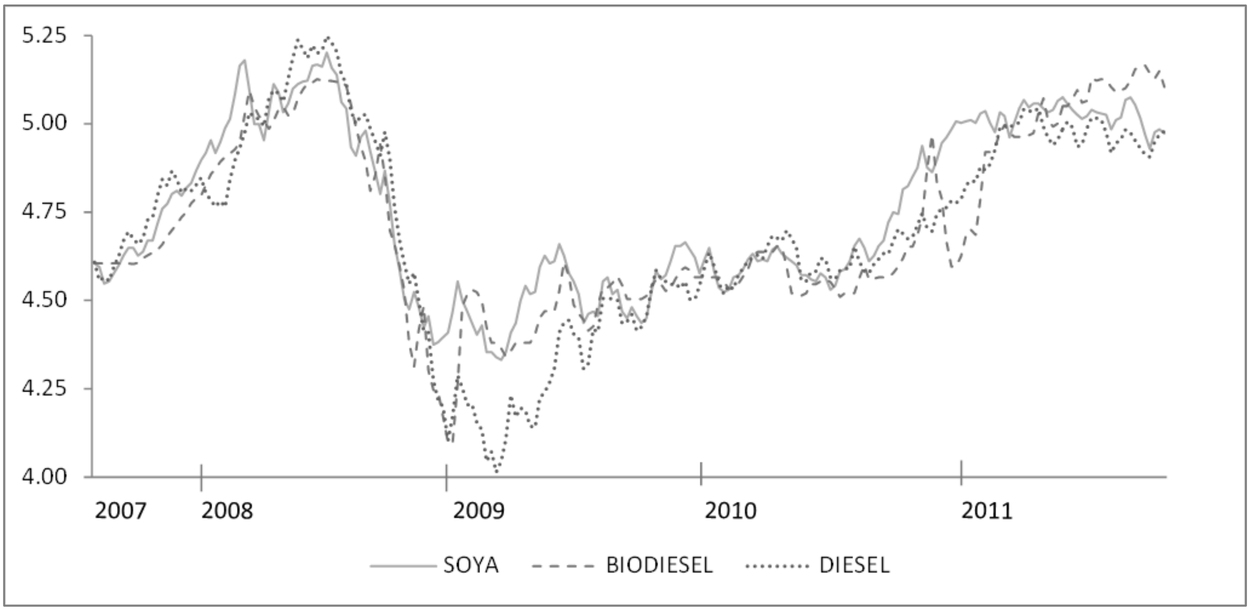
The data used for the analysis are derived from Datastream and the time series from this source are in all cases with a daily frequency. The content in Datastream – a data provider from Thomson Reuters - is a huge number of variables also in relation to fuel and biofuel prices, and the information stems from various other primary data collection agencies. In Table A1 1 (Appendix) all variables appearing in the analysis are listed, including the primary statistical sources for the respective variables. For biodiesel and ethanol the data typically only spans the time period since 2005-6, as the use of these fuels for transport purposes have only been of a noticeable magnitude during the last decade. Prices relationships for ethanol and biodiesel are analyzed for the USA and Europe and hence the data collected are nominated in the respective currencies, i.e. US Dollars and Euros per unit of the fuels involved. The prices for the various commodities and fuels in Datastream are available in US Dollars, but as final consumption of biofuels and fossil fuels in Europe are carried out in Euros, this currency is used in the latter case. Nominal prices are used throughout the analysis and the daily data have been converted to weekly frequencies as some of the more special commodities are traded on a weekly basis, i.e. the price information in Datastream relies on contracts only done once in a week. The next four graphs exhibit the data used in the empirical tests.

Figure 6.1 USA: Price indices of Corn, Ethanol and Gasoline, October 2005 – December 2012 (log values)



Note: Indices of the prices (value 100 in October 2005) in logs, weekly data. See the Appendix for further details.

Figure 6.2 USA: Price indices of Soya oil, Biodiesel and Diesel, August 2007 – October 2011 (log values)

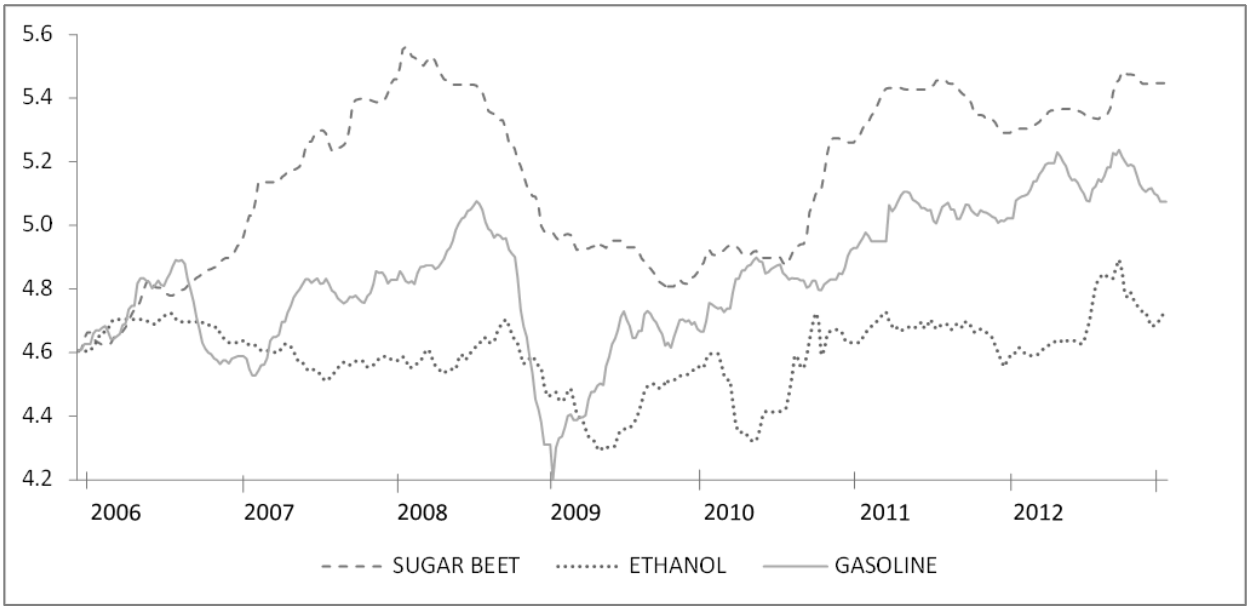


Note: Indices of the prices (value 100 in August 2007) in logs, weekly data. The biodiesel prices ending November 2011 and hence the analysis in this case will only involve the weekly data from 2007 to 2011 as presented in the graph. See the Appendix for further details.

For the USA Figure 6.1 and Figure 6.2 reveal that especially in the biodiesel cases there seems to be a close relationship between the relevant prices, i.e. soya as a feed stock to biodiesel and the latter linked to diesel prices. The empirical test will tell whether cointegration is in fact taking place, including some tests for the direction of causation.

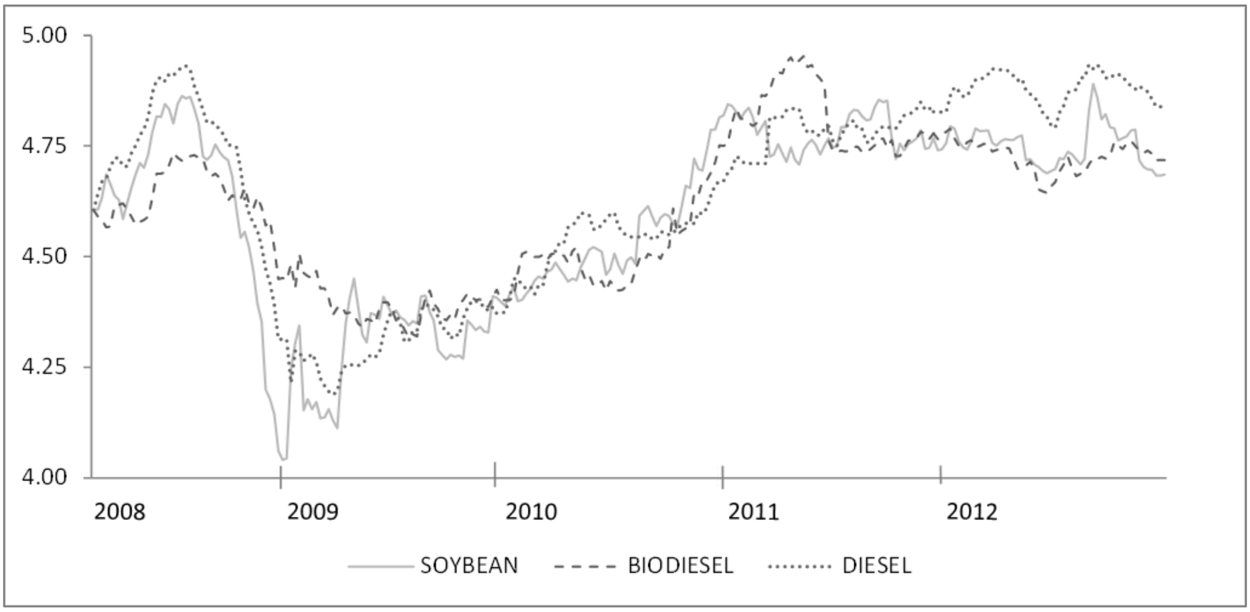
In the European case in Figure 6.3 and Figure 6.4 there appears more or less the same pattern as for the USA data. Again, for the ethanol-gasoline case the prices seem less closely related compared to the biodiesel-diesel case, but again formal time series test are required to avoid drawing any hasty conclusions.

Figure 6.3 Europe: Price indices of Sugar beet, Ethanol and Gasoline, January 2006 – December 2012 (log values)



Note: Indices of the prices (value 100 in January 2006) in logs, weekly data. See the Appendix for further details.

Figure 6.4 Europe: Price indices of Soybean, Biodiesel and Diesel, February 2008 – December 2012 (log values)



Note: Indices of the prices (value 100 in February 2008) in logs, weekly data. See the Appendix for further details.

6.6 Methodology

The time series properties of the agricultural commodities and energy prices from part 3 are first analysed with respect to integration. Usually, such price variables are found to be non-stationary in levels, which are also the general conclusions from the studies referred to in part 2 and also addressing and testing the questions of non-stationarity and stochastic trends. Consequently, the Dickey-Fuller unit root test (ADF) is performed for the crude oil price variables, and Table 6.1 exhibits the test statistics.

Table 6.1 ADF Unit Root tests of prices of agricultural commodities and fuels (Weekly data)

	Level	First difference	Weekly data from:
USA			
Corn	-0.942{3}	-8.913**{6}	2000:02:04
Ethanol	-2.780*{1}	-14.186**{0}	2005:11:11
Gasoline	-1.890{3}	-12.245**{2}	2000:02:04
Biodiesel	-1.031{6}	-5.537**{6}	2007:08:03#
Diesel	-0.802{3}	-10.034**{6}	2000:02:04
Soya oil	-1.341{1}	-9.931**{5}	2000:01:21
Europe			
Sugarbeet	-1.800{5}	-6.642**{4}	2001:12:21
Ethanol	-2.417{5}	-5.406**{6}	2006:01:20
Gasoline	-2.665{3}	-7.428**{2}	2005:02:04
Biodiesel	-1.180{0}	-15.120**{0}	2007:11:16
Diesel	-1.977{3}	-5.770**{6}	2005:02:04
Soybean	-1.730{1}	-13.035**{0}	2008:02:29

Notes: All variables in log values. Weekly data of biofuel prices with lags are included in the ADF unit root test as indicated by the {} parenthesis. The five per cent and ten per cent critical values are -2.87 and -2.57, respectively (approximate values, as the number of observations differ among the variables included in Table 6.1). A * indicates significance at the ten per cent level and ** significant at the five per cent level. #The number of observations for US biodiesel ending November 2011; all other data ending December 31, 2012.

The inclusion of lags in the ADF unit root test is chosen from the Akaike information criterion (AIC) values when testing down from an initial number of six lags. Deterministic trend has also been investigated for in the unit root tests, but no evidence of trend-stationarity is revealed for the respective variables and hence these tests are not included in Table 6.1. None of the test statistics were found significant at the five per cent critical levels, but in the US case of ethanol rejection of the unit root null hypothesis was found at the ten per cent level of significance as indicated in the table. The first difference values of all variables strongly indicate stationarity, thus excluding higher order of integration than one.

The overall conclusion seems to be all price variables are non-stationary I(1)-variables, and the next step will be to test for cointegrating relationships. The Johansen (1991) multivariate maximum likelihood approach to cointegration is followed where a vector autoregressive (VAR) model is reparameterized into an error-correction form, like equation (1) in the bivariate case assuming one cointegration vector.

$$\begin{bmatrix}\Delta P_{1,t}\\ \Delta P_{2,t}\end{bmatrix} = \begin{bmatrix}\mu_1\\ \mu_2\end{bmatrix} + \begin{bmatrix}\alpha_1\\ \alpha_2\end{bmatrix}\left(\beta_1\, P_{1,t-1} + \beta_2\, P_{2,t-1}\right) + A_1 \begin{bmatrix}\Delta P_{1,t-1}\\ \Delta P_{2,t-1}\end{bmatrix} + \cdots A_k \begin{bmatrix}\Delta P_{1,t-k}\\ \Delta P_{2,t-k}\end{bmatrix} + \begin{bmatrix}\varepsilon_{1t}\\ \varepsilon_{2t}\end{bmatrix} \quad (1)$$

The short-run dynamics are captured by the parameters in the A_k matrices and if the linear combination of the prices being stationary the error-correction model is well-defined. The Johansen methodology is a test for the number of cointegration vectors in the model. In the present analysis the test procedure will be both bivariate and trivariate cases of the variables from Table 6.1, and the most interesting case – from an economic point of view – will appear like equation (1). The system may be normalized to β_1=1 and hence the cointegration vector will be (1, β_2), and the factor loadings (α_1, α_2) contain information on the adjustment process towards the log-run relationship[4].

In the empirical tests for cointegration the Johansen methodology will be applied to the data exhibited in part 3 and divided into the four cases, i.e. the biofuel cases as represented by ethanol and biodiesel for the USA and Europe, respectively[5]. For each case the test procedure will firstly be done in the form of three bivariate tests for cointegration, e.g. for the data in Figure 6.1 this will involve the US prices of corn, ethanol and gasoline. If cointegration is found for corn and ethanol prices, and likewise ethanol and gasoline prices are cointegrated, then for these results to be consistent there must also be cointegration for corn and gasoline. In case the latter does not hold, some doubts may arise concerning the validity of the first part of the tests or alternatively, a better specification will be a three-variable model, cf. Figure 6.2 and Figure 6.4 which may indicate close relationships for the biodiesel case. The time spans of the data to be included in the empirical tests are relatively short, mainly due to the biofuel data, but for some variables like e.g. corn and soya data are available for several more years. Among the results from the literature on biofuels, cf. part two, is some sensitivity with regard to the choice of time period, e.g. the time switching models applied in some studies. Therefore, the same time span is kept for each of the four cases involving tests for cointegration.

[4] If e.g. α_1 is significant then a shift in P_2 will influence ΔP_1.
[5] Corresponding to the data in figures 1 to 4.

6.7 Empirical results from cointegration tests

In line with the testing methodology presented in part 4 the first step will be the Johansen cointegration tests for all the bivariate cases. This will be reduced rank regressions for the VAR model with test of significance levels of the eigenvalues (trace test) presented in Table 6.2 and Table 6.3 for the USA and Europe, respectively.

Table 6.2 Bivariate Johansen tests for cointegration, USA (Weekly data)

Variables	**Rank**	**Eigenvalue**	**Trace# (p-value)**	**Lags**
Corn	0	0.022	14.107 (*0.29*)	2
Ethanol	1	0.016	5.730 (*0.22*)	
Gasoline	0	0.030	18.136* (*0.10*)	3
Ethanol	1	0.019	7.042 (*0.13*)	
Corn	0	0.015	11.729 (*0.48*)	4
Gasoline	1	0.003	1.873 (*0.80*)	
Biodiesel	0	0.066	16.538 (*0.15*)	4
Diesel	1	0.010	2.176 (*0.74*)	
Biodiesel	0	0.083	20.672** (*0.04*)	4
Soya oil	1	0.011	9.142 (*0.69*)	
Diesel	0	0.017	14.123 (*0.29*)	3
Soya oil	1	0.004	2.619 (*0.66*)	

Notes. All variables in log values. The Trace# test has a null hypothesis of at most r cointegration vectors against the alternative of more than r vectors. Frac95 is the 5 % critical value, and # indicates a small sample corrected (Trace) test statistic. Weekly data corresponding to the time periods indicated in Table 6.2 are used in all tests, and therefore there will be a varying number of observations in the respective cases (the number of observations for biodiesel is relatively small with a time span from August 2007 to November 2011). The number of lags is set to 6 and reduced lag χ^2-tests performed for the VAR models with the final number of lags included as indicated in the table. A constant is included in the cointegration vector, but no deterministic time trend. Test statistic with ** significant at the 5 % critical level, and * for the 10 % level of significance.

For corn, ethanol and gasoline in the USA there is evidence of cointegration in one case, i.e. between ethanol and gasoline where a hypothesis of one cointegration vector (r=1) cannot be rejected if the ten per cent level of significance is applied. Corn prices should not be linked in the cointegration sense to the fuel prices according to the other two tests and thus, there is not much evidence for long-run relationships for this part of US fuels. For the next case in Table 6.2, one cointegration vector between soya and biodiesel is found at the five per cent level of significance, but diesel prices are not sharing the same stochastic trend as no evidence for cointegration is present in relation to soya oil or biodiesel. The tests for the European data - with prices in Euros per unit - are presented in Table 6.3.

Table 6.3 Bivariate Johansen tests for cointegration, Europe (Weekly data)

Variables	Rank	Eigenvalue	Trace# (p-value)	Lags
Sugarbeet	0	0.024	13.123 (*0.36*)	6
Ethanol	1	0.011	4.182 (*0.40*)	
Gasoline	0	0.038	18.021* (*0.10*)	4
Ethanol	1	0.012	4.297 (*0.38*)	
Sugarbeet	0	0.026	12.724 (*0.40*)	4
Gasoline	1	0.006	2.396 (*0.70*)	
Biodiesel	0	0.021	6.509 (*0.92*)	2
Diesel	1	0.004	0.970 (*0.94*)	
Biodiesel	0	0.061	17.975* (*0.10*)	3
Soybean	1	0.010	2.301 (*0.72*)	
Diesel	0	0.067	19.536* (*0.06*)	4
Soybean	1	0.011	2.595 (*0.66*)	

Note. See the notes to Table 6.2.

In the European case the results are relatively similar to the USA case from Table 6.2. Gasoline and ethanol are again found cointegrated at the ten per cent level of significance, and with no relationships to the sugar beet feed stock in the other cases. For soybean there seems to be a long-run relationship to both biodiesel and diesel, but the prices of the latter two fuels are not at all close to a significant test statistic for cointegration. This may cast doubt on the validity of the tests for this part of the European case, and will be further investigated by including the ADF-test for cointegration in tables 6.4 to 6.6, as well as tests for the three-variable model presented in the tables 6.7 and 6.8.

In relation to ethanol the results are identical for the USA and Europe as cointegration between ethanol and gasoline is found in both cases. These results are only valid assuming a ten per cent level of significance and therefore the ADF/OLS cointegration test is also included as an alternative test methodology, cf. Table 6.4. Likewise, the biodiesel relationships are tested with the same procedure and the results presented in Table 6.5.

Table 6.4 Ethanol OLS cointegration regressions

USA:	Ethanol	Europe:	Ethanol
Constant	0.384	Constant	4.618
Gasoline	0.444	Gasoline	0.276
$\bar{R}^2$	0.39		0.27
DW	0.08		0.04
ADF {lags}	-3.402**{1}		-2.966{3}
N	375		367

Note: All variables are in log values. Lags chosen according to the AIC-criteria, and ** indicates significant at the five per cent level, where -3.35 and -3.06 are the five and ten per cent critical values, respectively.

Table 6.5 Biodiesel/Diesel OLS cointegration regressions

USA:	Biodiesel	Europe:	Biodiesel	Diesel
Constant	2.164	Constant	-4.413	-0.083
Soya oil	0.984	Soybean	0.661	0.970
$\bar{R}^2$	0.84		0.71	0.84
DW	0.29		0.11	0.18
ADF {lags}	-3.608**{4}		-2.732{2}	-2.825{3}
N	218		254	253

Note: All variables are in log values. Lags chosen according to the AIC-criteria, and ** indicates significant at the five per cent level, where -3.35 and -3.06 are the five and ten per cent critical values, respectively.

According to the OLS regressions ethanol and gasoline are cointegrated for the USA and significant at least the five per cent level according to the ADF-test statistics. For Europe the test statistic is just below the ten per cent critical level and thus not rejecting a null hypothesis of no cointegration - although not deviating that much from the Johansen test result in Table 6.3. In the case of biodiesel in Table 6.5, cointegration is found in relation to the feed stocks for biodiesel in the USA, but no evidence of long-run relationships for the soybean-biodiesel/diesel price variables is found in Europe. Thus, the results from the Johansen methodology are partly confirmed by the OLS/ADF-tests, with the findings for USA identical for the two test procedures. To further investigate for causality relations we report the estimates of the cointegration vectors and factor loadings according to the Johansen test for the bivariate cases of ethanol and gasoline in Table 6.6. In relation to the biodiesel case more evidence of a three-variable model including biodiesel, diesel and soya is found, and reported in tables 6.7 and 6.8.

Table 6.6 Johansen estimates of the cointegration vectors. Model: Ethanol and Gasoline

	USA	**Europe**
Cointegrationvector		
β_1	1.000	1.000
β_2	-0.510	-0.538
Constant	-0.317	-2.975
Factor loadings		
α_1	-0.039**(-2.989)	-0.025**(-3.579)
α_2	0.019 (1.237)	0.009 (0.874)
Test of weak exogeneity		
Ethanol, $\chi^2(1)$:	3.118 [0.077]	8.630 [0.00]
Gasoline, $\chi^2(1)$:	0.542 [0.461]	0.526 [0.47]
Residual test statistics		
LM(1)	3.83 [0.43]	1.67 [0.80]
Normality		
Ethanol	2.66 [0.26]	15.13 [0.00]
Gasoline	9.38 [0.01]	0.28 [0.87]

Notes: β_1 is the parameter to ethanol and normalized to 1, and the cointegration vector reported as (β_1, β_2, constant) and thus the parameter β_2 for gasoline will be positive in the usual form of a linear relationship. For the factor loadings *t*-values in parenthesis and ** indicates significant at the 5 per cent level. For the exogeneity and residual tests the *p*-values are reported in parenthesis. The residual test statistics are a Lagrange multiplier test for first order autocorrelation, LM(1), and for normality it is the Jarque-Beraχ^2 test where outliers (more than 2.25 of the standard error of residuals) have been deleted.

The estimates of the cointegration β-vector for ethanol-gasoline are very similar when comparing the USA and Europe, with a value of approximately 0.5 in both cases, and slightly larger than the estimates from the OLS regressions in Table 6.4. The factor loadings for the equations in the model indicate that causality will run from gasoline prices to ethanol prices as α_1 is the parameter to the cointegration vector of the ethanol equation. This is similar to the test results for weak exogeneity. The residual test statistics show no first order autocorrelation in the residuals of the cointegration model according to the LM(1) test. The residual values show up with some outliers that probably might be due to the use of weekly data as there can be both random shocks and reporting errors in the data. The distribution of residuals do not seem that far away from the normal distribution but with outliers of both negative and positive values the test statistic clearly rejects such a hypothesis. When deleting outliers, defined here as more than 2.25 the standard error[6], the test results appear as reported in the last part of Table 6.6. The test statistic is reported separately for the two equations in the model, i.e. ethanol and gasoline. Still, there are two cases of rejection of normally distributed residuals which might raise some doubt about the validity of the ethanol-gasoline relationship, although the results seem very much in accordance with *a priori* economics expectations. Trying to expand the model to a three variable case, cf. figures 6.1 and 6.3, does not seem to produce reliable results and thus, the final findings will be as exhibited in Table 6.6. For the biodiesel case the three variable version of the modelling procedure is presented in tables 6.7 and 6.8.

Table 6.7 Johansen tests for cointegration, USA and Europe. Model: Biodiesel, Diesel and Soya

	Rank	**Eigenvalue**	**Trace# (p-value)**	**Lags**
USA	0	0.082	32.412* (0.10)	4
	1	0.058	14.943 (0.24)	
	2	0.012	2.513 (0.68)	
Europe	0	0.138	42.956** (0.01)	2
	1	0.018	6.067 (0.94)	
	2	0.007	1.654 (0.84)	

Note: The same test procedure as indicated in the note to Table 6.2 is followed in the present case.

The conclusion from the test results in Table 6.7 will be one cointegration vector for both the USA and Europe, and with the most convincing Trace test statistic for the latter. Table 6.8 reports the final model of the biodiesel case.

[6] From 366 observations the number of deleted outliers is 13. Including these outliers also reveals problems of heteroscedasticity, but again deleting outliers gives in most cases satisfactory results from a LMARCH(1) test.

Table 6.8 Johansen estimates of the cointegration vectors. Model: Biodiesel, Diesel and Soya

	USA	**Europe**
Cointegrationvector		
β_1	1.000	1.000
β_2	-0.038	1.651
β_3	-1.000	-2.684
Constant	-2.147	7.357
Factor loadings		
α_1	-0.120**(-4.279)	-0.023**(-3.388)
α_2	0.008 (0.252)	-0.022**(-3.673)
α_3	0.025 (0.813)	0.029**(2.551)
Test of weak exogeneity		
Biodiesel	5.650 [0.017]	9.937 [0.00]
Diesel	0.026 [0.871]	12.369 [0.00]
Soya	0.560 [0.454]	6.012 [0.01]
Residual test statistics		
LM(1)	8.11 [0.52]	10.26 [0.33]
Normality		
Biodiesel	4.37 [0.11]	0.72 [0.70]
Diesel	2.27 [0.32]	3.23 [0.20]
Soya	4.20 [0.12]	2.16 [0.34]

Notes: β_1 is the parameter to biodiesel and normalized to 1, and the cointegration vector reported as ($\beta_1, \beta_2, \beta_3,$ constant) and thus the parameters β_2 and β_3 will have the opposite sign in the usual form of a linear relationship. For the factor loadings *t*-values in parenthesis and ** indicates significant at the 5 per cent level. For the exogeneity and residual tests the *p*-values are reported in parenthesis. The residual test statistics are a Lagrange multiplier test for first order autocorrelation, LM(1), and for normality it is the Jarque-Beraχ^2 test where outliers (more than 2.25 of the standard error of residuals) have been deleted.

The cointegration vectors for the USA and Europe appear to be very different and as biodiesel is the major biofuel in Europe the latter may be of most interest. From the factor loadings and the exogeneity tests the European market for biodiesel seems to be characterized with significant interrelationship in both directions for all the variables included, whereas for the USA fossil diesel and soya are weakly exogenous in contrast to biodiesel. The residual tests indicate no autocorrelation of first order, and when deleting outliers as discussed in relation to Table 6.6 all residuals will fulfil the assumption of normality in both cases[7]. With log values of the variables the parameter estimates are to be interpreted as long-run elasticities between level values of the respective variables, and for the USA the strongest relationship is found with a unity value for the soya variable ($\beta_3 = 1$), cf. Figure 6.1 where the development of biodiesel and soya prices is very close. If the European market for biodiesel is the relatively most developed or mature another finding from Table 6.8 might be that closer links or causality will develop between biodiesel, diesel and soya in the USA.

6.8 Conclusions

The literature on long-run relationships between the prices of biofuels, fossil fuels and agricultural commodities present varying conclusions on this issue, and the results seem very dependent on the data used as well as the choice of time span and econometric methodology. The present analysis takes recent data (2007 to 2012) of similar price variables for a comparative analysis between the USA and Europe, and with prices of the respective fuels in the relevant currencies, i.e. US dollars and Euros. The empirical tests for cointegration show rather identical results for these two major regions of biofuel usage. There is some evidence for a stationary long-run relationship between ethanol and gasoline for the USA, but with no links to the feed stock of corn (USA). For Europe there is at a ten per cent level of significance a similar relationship between ethanol and gasoline.

In the case of biodiesel the evidence of cointegration is much stronger as long-run relationships between biodiesel, diesel and soya oil (USA) - and biodiesel, diesel and soybean (Europe) – show up to be significant from the Johansen multivariate cointegration test. Finally, the analysis also addresses the question of causality from the estimated factor loadings and tests for weak exogeneity in the VAR included in the Johansen test procedure. For both the USA and Europe the influence runs from gasoline prices to ethanol prices, and not vice versa. In the case of biodiesel the influence is coming from prices of the feed stocks (soya) and fossil diesel to the US biodiesel fuel, in contrast to Europe where the biodiesel markets seem more integrated where none of the biodiesel, diesel or soybean prices are found to be (weakly) exogenous. Thus, there is not in general found evidence for a hypothesis of biofuels influencing prices of agricultural commodities or fossil fuel prices, which is not in contrast to *a priori* expectations, but the findings seem rather robust as the comparative analysis exhibit somewhat similar conclusions for the two regions. There is a vast number of

[7]Like for the ethanol model, the normality assumption will not hold when outliers are included, but again it is a relatively small number of outliers deleted.

agricultural feed stocks for biofuels – and similarly, various intermediate inputs for the production of biofuel – and therefore it cannot be surprising that the existing literature and empirical tests present varying results in relation to biofuel prices.

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Appendix

Table A1 1 List of commodities and statistical sources

Commodity	Source	*Datastream* name (and variable name in the text)
USA (prices in USD per unit):		
Corn:		
Corn No. 2 Yellow, Mid West	Dept. Agri.	CORNUS2 (Corn)
Soya:		
Soyaoil, CrudeDecatur	Dept. Agri.	SOYAOIL (Soya oil)
Ethanol:		
Ethanol, Chicago	TR	ETHACHG (Ethanol)
Fuels:		
Biodiesel, B100, Mid West	ICIS	BIODUSG (Biodiesel)
Gasoline (unleaded, premium), New York Harbor	ICIS	GASUSPB (Gasoline)
Diesel (low sulphur), New York Harbor	TR	DIESELF (Diesel)
Europe (prices in Euro per unit):		
Inputs for the biodiesel industry:		
Soybean Methyl Ester (B100, T2), Rotterdam	HBI	HBISMER (Soybean)
Input for the ethanol industry:		

SugarBeet Pulp (Italian)	TR	BEETPLP (Sugarbeet)
Ethanol:		
Ethanol(T2), Rotterdam	ICIS	ETHEUT2 (Ethanol)
Fuels:		
Biodiesel (excl. tax), Germany	DS	BDNWEDE (Biodiesel)
Diesel (excl. tax), EU27	ECFIN	DIEEUEE (Diesel)
Gasoline (unleaded, excl. tax), EU27	TR	UNLEUEE (Gasoline)

Statistical sources (access via Datastream, January 2013):

TR: Thomson Reuters

ICIS: Petrochemical market information provider, www.icis.com

Dept. Agri: US Department of Agriculture

DS: *Datastream*

HBI: Oleochemical market information provider, www.hbint.com

ECFIN: Directorate General for Economic and Financial Affairs (DG ECFIN, EU).

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