Overcoming Barriers to Onshore and Offshore Wind Power Development—A Developers' Perspective on the Effect of Support Policies

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“Of all the forces of nature, I should think the wind contains the largest amount of motive power—that is, power to move things. […] As yet, the wind is an untamed, and unharnessed force; and quite possibly one of the greatest discoveries hereafter to be made, will be the taming, and harnessing of it.”

— Abraham Lincoln

In a speech given during the 1860 presidential campaign. Printed in the Executive Intelligence Review, January, 1992

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ABSTRACT

Climate change is on the verge of becoming a severe threat to mankind. It is widely acknowledged that the emissions of greenhouse gases need to be reduced drastically to prevent major damages to the environment and society. As the power sector is one of the biggest emission sources of greenhouse gases a step-change transformation of energy systems towards zero-carbon power generation will be indispensible. Renewable energy technologies (RETs) will play a pivotal role in this endeavor. As regulators across the globe take actions to foster the swift development and deployment of RETs it will be crucial to identify and employ smart energy policies to drive effective and efficient diffusion of RETs.

Using onshore and offshore wind power as research cases, this dissertation strives to identify existing barriers to RET deployment and derive recommendations on which policy measures can be employed to overcome them. Throughout all three studies, the analyses adopt the perspective of the main addressees of policy instruments—developer and investor companies. The first study investigates the key barriers of onshore wind power development and reveals the preference values that developers place on various policy settings. The second study scrutinizes current barriers and deployment dynamics in developing offshore wind power. The third study analyzes the profitability prospects of various offshore wind power locations in Europe by modeling location-dependent costs, wind resources, and remuneration policy schemes.

The main contributions of this dissertation lie in providing a rich set of new, empirical data for both onshore and offshore wind power; in expanding the scientific knowledge about developing the nascent offshore wind power technology; and in offering a framework that captures the determinants that developer companies use to assess policy regimes.

The results indicate that regulators can address many barriers to developing wind power by means that go beyond monetary support. Developers highly value policy measures that mitigate risks, both concrete and perceived. Those include providing reliable, clear, and stable support schemes, permitting procedures, and grid access regulations. Furthermore, the studies indicate that the success of technology support does not only depend on the choice of the primary deployment policy instrument but rather on its specific implementation design and on suitable secondary regulatory aspects. Together these can have significant impact on how developers perceive the attractiveness of a given policy regime as a whole.

ZUSAMMENFASSUNG

Der Klimawandel entwickelt sich zu einer ernsthaften Bedrohung für die Menschheit. Es herrscht weitgehend Konsens, dass die Emissionen von Treibhausgasen drastisch reduziert werden müssen, um große Schäden für Umwelt und Gesellschaft zu vermeiden. Die Transformation des Energiesektors—einem der größten Verursacher von Treibhausgas-emissionen—ist dringend erforderlich, um kohlenstofffreie Erzeugungsformen zu ermöglichen. In diesem Zusammenhang spielen erneuerbare Energien (EE) eine entscheidende Rolle. Weltweit ergreifen Regierungen Maßnahmen, die Entwicklung und den Ausbau von EE zu fördern. Hierbei wird eine intelligente Energiepolitik erforderlich sein, um die Diffusion von EE möglichst wirkungsvoll und effizient voranzutreiben.

Ziel dieser Dissertation ist es, bestehende Barrieren für die Entwicklung von EE zu identifizieren und daraus Implikationen für Energiepolitik abzuleiten. Dazu werden in drei Studien zu Onshore- und Offshore-Windkraft Politikinstrumente aus der Perspektive von Entwicklern und Investoren analysiert. Die erste Studie untersucht die Hauptbarrieren für die Entwicklung von Onshore-Windkraft. Sie zeigt auf, welche Nutzenwerte Entwickler diversen politischen Rahmenbedingungen zuordnen. Die zweite Studie befasst sich mit Barrieren und Entwicklungsdynamiken bei der Offshore-Windkraft. Die dritte Studie analysiert die Rentabilität verschiedener europäischer Offshore-Windkraft Projekte unter Berücksichtigung von standortspezifischen Kosten, Windstärken und Vergütungssystemen.

Die Hauptbeiträge der Arbeit bestehen (1) in der Erhebung eines breiten Spektrums an neuen, empirischen Daten zur Entwicklung von Onshore- und Offshore-Windkraft; (2) in der Erweiterung des Wissensstands im Bereich der noch jungen Technologie Offshore-Windkraft; und (3) in der Entwicklung eines Models, welches die Bewertungskriterien von Entwicklungsfirmen für die Einschätzung von politischen Rahmenbedingungen aufzeigt.

Die Analysen zeigen auf, dass Regulatoren auch jenseits von finanziellen Anreizen über großen Einfluss auf den Abbau von Entwicklungshürden bei der Windkraft verfügen. Entwicklungsunternehmen legen großen Wert auf Maßnahmen zur Risikominimierung. Der Fokus sollte hier auf der Klarheit und Verlässlichkeit von Anreizsystemen, Zulassungs-, und Netzzugangsbestimmungen liegen. Desweiteren legen die Ergebnisse nahe, dass der Erfolg von Technologiepolitik nicht nur von der Wahl der primären Anreizinstrumente abhängt, sondern auch maßgeblich von der Art und Weise derer Implementierung sowie geeigneter

Begleitmaßnahmen. Es wird dargelegt, wie die Summe der Rahmenbestimmungen die Wahrnehmung der Entwickler auf die Attraktivität eines Investitionsstandortes prägen.

Chapter 1

Chapter 1: Introduction and overview

1 INTRODUCTION

1.1 Facing the climate change threat

Climate change is a severe threat for modern societies. Despite the reoccurring challenges by inveterate skeptics, it is common consensus that most of the observed increase in global average temperatures is caused by an increase in anthropogenic green house gases (GHG) (IPCC 2007a). Since the beginning of the industrialization temperatures have risen by more than 0.7 degrees and the rate of increase has accelerated in the last 50 years[1] (IPCC 2007b).

The scientific community postulated the goal of limiting the further increase of global average temperatures to no more than 2 degrees Celsius above pre-industrial levels in order to avert serious, potentially irrecoverable damages to ecosystems, and ultimately, mankind (Stern 2007; IPCC 2007c). This 2 degree Celsius target can only be achieved if societies around the world make substantial efforts to reduce GHG emissions (den Elzen & Meinshausen 2006).

The magnitude of the challenge is enormous. Historically, the annual GHG emissions have been rising constantly over the last decades, registering a 70% increase between 1970 and 2004. Very recent data suggests that emissions might be rising at record levels (CDIAC 2011), exceeding even the worst-case scenarios described by the Intergovernmental Panel on Climate Change (IPCC 2007a). An unprecedented turn-around is needed. The IPCC calculates that annual emissions have to be reduced by up to 80% compared to the level in 1990.

However, this will be a daunting task in the face of global population growth and continued economic development. Figure 1 illustrates the contrasting trajectories of expected GDP growth and required emission pathways. Depending on the emission scenarios defined by the Intergovernmental Panel on Climate Change (2000), the decoupling factor between those two trajectories will range between 3x (A2 scenario) to as much as 43x (A1T) until the end of the century—an unprecedented order of magnitude.

[1] The IPCC provides uncertainty bands: 0.76°C increase (0.57°C to 0.95°C) between 1850 to 1899 and 2001 to 2005.

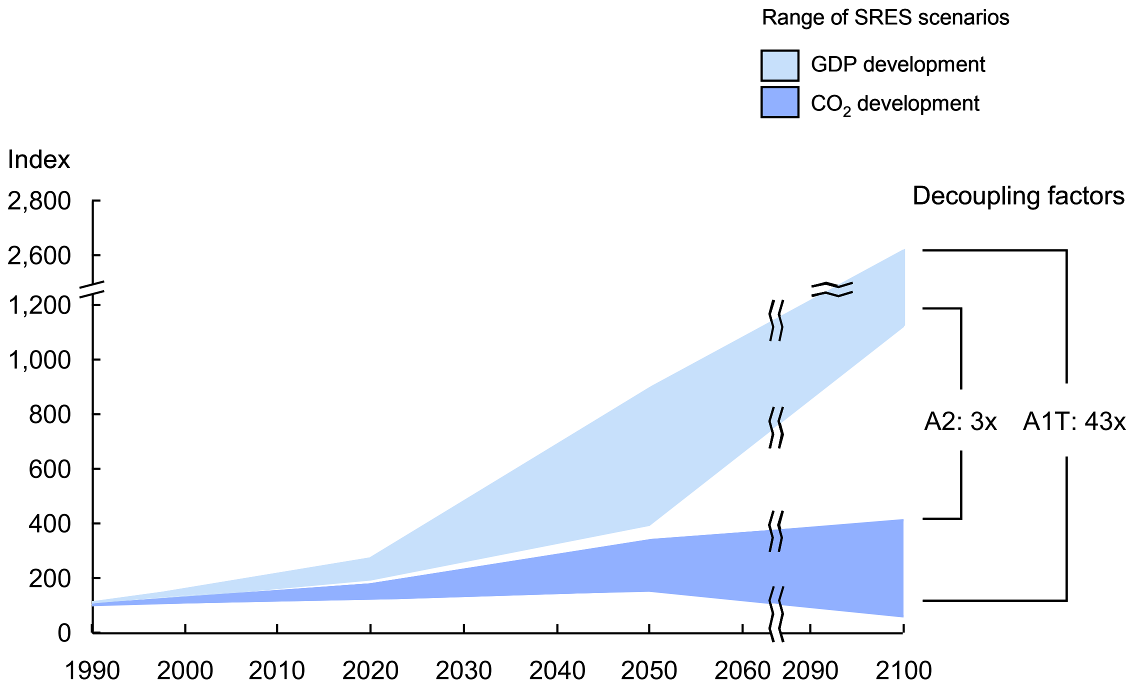

Figure 1: Development of global GDP and global CO_2 emissions from fossil fuels and land use
Source: (IPCC 2000)

Thus, decoupling economic growth from GHG emission growth will be one of the pivotal challenges for the 21st century. It is likely to require a combination of reducing energy intensity—the amount of energy used per unit of GDP—and reducing carbon intensity—the amount of CO2 emissions per unit of primary energy consumption (Luderer et al. 2009).

A substantial share of anthropogenic GHG emissions stems from the combustion of fossil fuels for energy production. Energy production in the power sector is the largest contributor to total annual GHG emissions, accounting for approximately 41% (IEA 2011). Many scientists argue that today's energy systems, and particularly electricity production systems, have to be drastically transformed towards zero-carbon emissions systems in order to achieve the ambitious emission targets (Sims et al. 2007; Verbruggen & Lauber 2009). A central question in this transformation process will be, which strategies, pathways, and technologies will be most appropriate to facilitate the decarbonization of the energy systems?

1.2 Transforming energy systems toward zero-carbon emissions

A variety of low or zero-carbon technologies is available to wean power systems off fossil fuels. These technologies include nuclear energy, carbon capture and storage solutions, and renewable energy technologies (RETs). So-called energy-environment-economy models show that decarbonizing power sectors can be feasible at moderate costs (Edenhofer et al. 2010). While there seem to be several different pathways and technology options that can be pursued renewable energy technologies (RETs) will certainly have to play a crucial role (Edenhofer et al. 2010).

The resource potentials of RETs are high: the technical potential of wind power alone exceeds current global electricity production by a factor of two[2] (IPCC 2011). Similarly, the technical potential of direct solar power would suffice to satisfy global energy demand many times over[3]. But how much of this technical potential will we be able to reap? Long-term scenario modeling suggests RETs could provide very high shares of future electricity production. REMIND, an integrated model comprising a macroeconomic system module and an energy system module, suggests that RETs could contribute as much as 90% of global electricity production in 2050 given a favorable policy scenario (Leimbach et al. 2010). Using a target-oriented scenario approach, the International Energy Agency estimates that RETs will assume up to 48% of power generation in 2050 (IEA 2010).

However, there is still a long way to go until such high penetration levels of RETs materialize. In 2008, RETs only accounted for 6.8% of global primary energy supply, not including traditional biomass in developing countries that contributes another 6.1% (IPCC 2011). Wind power and direct solar power still supply only negligible fractions of global energy supply, with 0.2% and 0.1% respectively.

Yet the case of RETs is multifaceted. Notwithstanding such low contribution levels, the recent dynamics of RETs expansion paints a promising picture. Global investments in renewable energy have been at constantly high rates for the last decade (see Figure 2). Starting out at USD 33 billion in 2004 investments levels have been growing at a compounded annual growth rate of 36% to reach USD 211 billion in 2010. This is particularly remarkable in the face of the financial crisis that has severely hampered investments in many sectors as of 2008.

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[2] Global technical potential of wind power: 180 EJ/yr. Gross global electricity production (2008): 73 EJ

[3] The IPCC (2011) cites various studies with estimations widely ranging from 1,338 to 14,778 EJ/yr for PV and 248 and 10,791 EJ/yr for CSP.

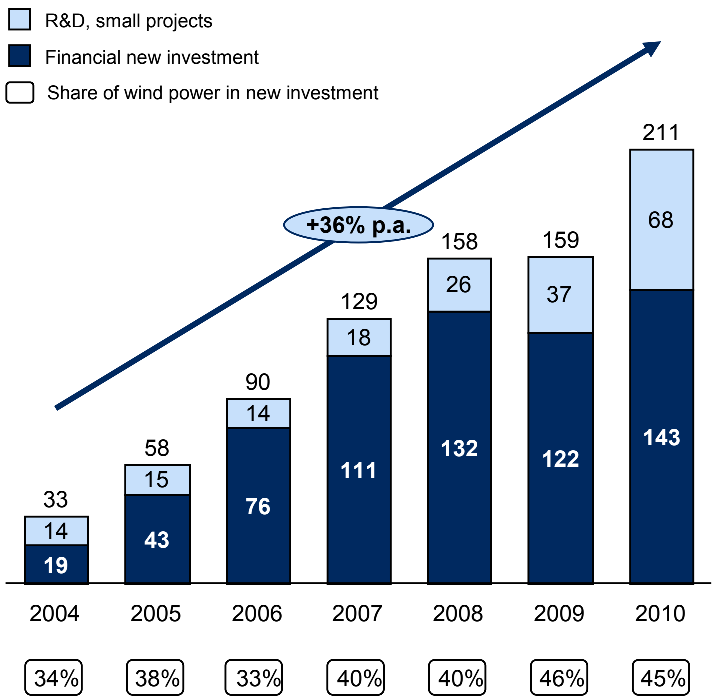

Figure 2: **Global new investments in renewable energy, USD billion**
Source: UNEP and BNEF (2011)

Among the various RETs that are employed today wind power plays a pivotal role in terms of both investment and power production capacity. Having captured the lion's share of investments throughout the last decade its share has been growing further, accounting for almost as much financial new investments as solar, biofuels, biomass, small hydro, geothermal, and marine power combined (UNEP & BNEF 2011). Installed capacity continued to grow fast with 41 GW additions in 2011 to reach a global total of 238 GW at the end of 2011 (GWEC 2012). In 2007 to 2009, wind power in Europe has even led all power generation capacity additions, trumping gas and coal installations (GWEC 2011).

This surge of RETs is urgently needed as developing countries have to satisfy vast electricity needs in the decades to come and developed countries are faced with aging power generating assets that need to be replaced. Each new GHG emitting power plant manifests a lock-in for years to come, rending low-stabilization pathways less likely (Vuuren et al. 2007; Kalkuhl et al. 2011). Despite the successful deployment of RETs there is a significant gap between required and actual capacity expansion levels. The International Energy Agency estimates that investors need to muster up roughly USD 800 billion on average per year from now until 2050 to enable the transformation of energy systems. This is a significant order of magnitude compared to the USD 143 billion investment in financial new investment (see Figure 2) that was realized in 2010.

However, so far it is not clear which sources should be tapped to provide the necessary capital and how sufficiently large amounts of investments can be steered into renewable energies. The scale of the required investments seem to be unprecedented: The European Climate Foundation estimates that energy systems in Europe will require 1.3 trillion EUR in the next 15 years - constituting a doubling of the historic investment rate (ECF 2010). As the rate of investment needs to grow and low-carbon power technologies are even more capital intensive than traditional power technologies the traditional actors in the power sector will not be able to provide enough capital to meet decarbonization targets under current energy market systems (ECF 2011).

This poses the question how required investments can be effectively channeled into transforming energy systems. All scenarios that are optimistic on future renewable energy deployment point out that adequate deployment policies will be crucial to that end. Smart renewable energy policy will be needed.

1.3 Incentivizing renewable energy investments with smart policies

One key barrier to deploying renewable energies is their lack of economic competitiveness: *"A comparison of LCOE of RE technologies with those of other technologies (nuclear, gas and coal power plants) shows that—at least as long as externalities are not taken into account RE sources are often not yet competitive with other sources, especially if they both feed into the electricity grid."* (IPCC 2011, p.846)

Figure 3 provides an overview of the levelized costs of electricity (LCOE) for various RETs.

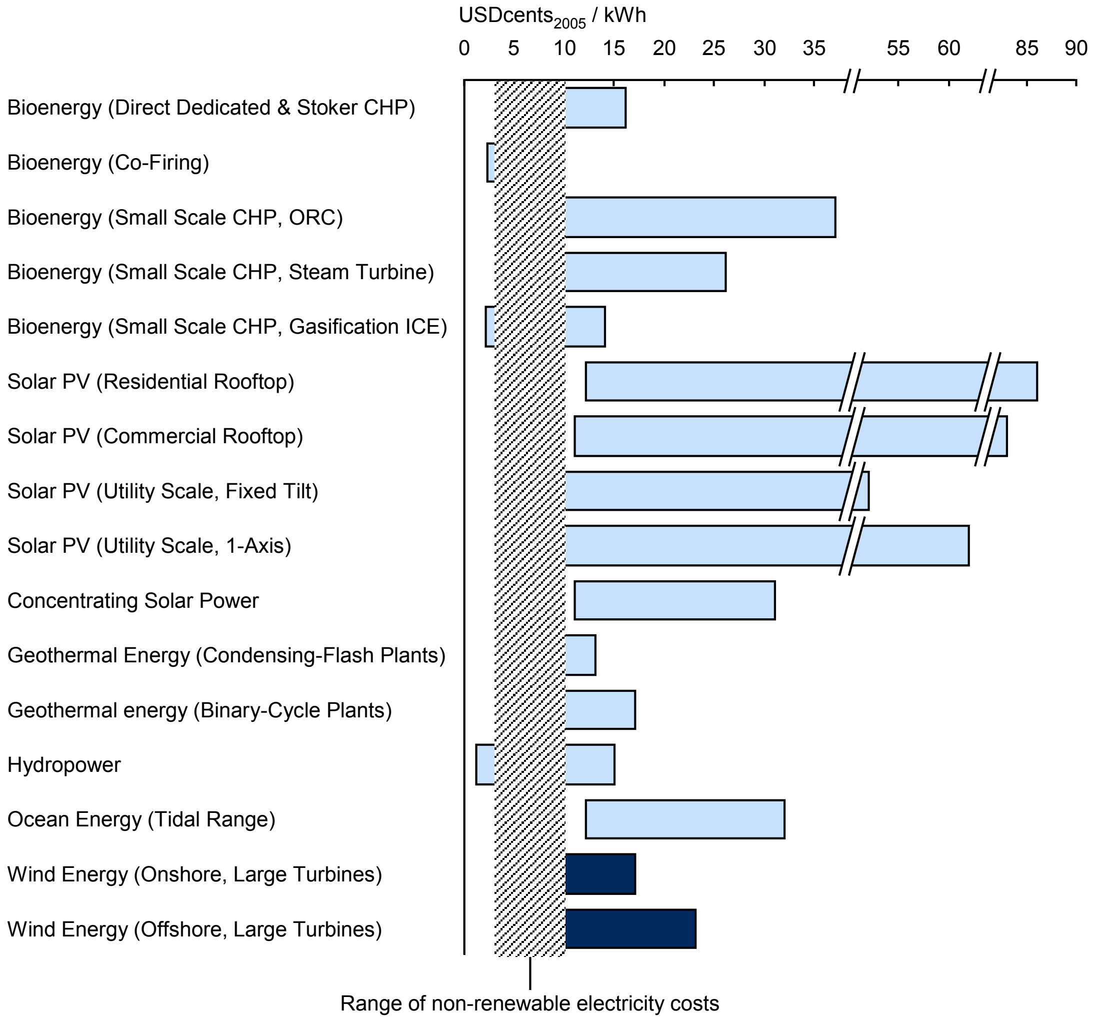

Figure 3: LCOE of renewable energy technologies[4;5]; shaded reference area shows range of LCOE of non-renewable electricity costs
Sources: Special Report on Renewable Energy Sources and Climate Change Mitigation (IPCC 2011, p.188)

While under best case assumptions (left hand side of the bars) some RETs seem to be competitive with non-renewable energy technologies, many RETs typically cannot yet compete in free markets with conventional power generating technologies. Furthermore, many intermittent RETs incur additional integration and balancing costs on a system level, which are not accounted for in Figure 3. Note that onshore wind power achieves competitively low LCOEs under favorable conditions, whereas offshore wind power still suffers from very high electricity generation costs.

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4 Ranges indicate extreme case assumptions available in the literature. Low-end numbers assume the lowest values for discount rate, investment costs, O&M and fuel costs, and highest capacity factor and life times. High-end numbers represent the opposite.

5 Note that Solar PV is much more competitive than indicated in this graph. The investment costs assumptions for Solar PV used in the SRREN are already obsolete due to recent drastic cost reductions. Even the best case assumptions on investment costs for commercial and residential rooftop PV are twice as expensive as current real market prices.

Thus, RETs still largely depend on policy support. Empiric success stories of renewable deployment in Denmark, Germany, Spain and China indicate that smart policies can boost deployment dynamics significantly (Pablo Del Río 2008; GWEC 2012; BMU 2012). However, as RETs reach higher penetration rates deployment support policies as well as market structures need to grow in sophistication: *"This goes far beyond creating a playground for RES-E. To make sure that this process is carried out in an economically efficient way, it is important to design a regulatory market framework that can accommodate the complexity of this enterprise"* (Verbruggen & Lauber 2009, p.5732).

It will be crucial for scholars and policy makers alike to gain a thorough understanding on how to design effective energy policies to achieve long-term targets while maintaining cost-efficiency. Klessmann et al. (2011) formulate the ambition and provide a short list of starting points: *"Success factors for reaching the 2020 targets include the implementation of effective and efficient policies that pro-mote high project success rates and attract sufficient investments, the reduction of administrative and grid-access barriers, especially in currently less advanced countries, upgrading the power grid infrastructure […]"*(p.7656).

Hence, this dissertation strives to contribute to an improved understanding of RET deployment dynamics and energy policy design. The following sections of this chapter provide an overview of the relevant literature on renewable energy deployment (section 2), describe the overall objective of the presented research (section 3), and lay out the employed methods (section 4). After presenting the individual research papers in Chapters 2 to 4, the conclusions in Chapter 5 shed light on the dissertation's contributions, emphasizing the implications for policy makers, and concluding in suggestions for future research avenues.

1.4 Literature context

1.4.1 The quest for effective and efficient renewable energy policies

Transforming the world's dependence on fossil fuel-based energy systems to low-carbon energy systems is a tremendous task. Smart energy policy strategies are needed, therefore, to realize this transition as quickly and efficiently as possible. Policy makers worldwide have started to respond to this challenge by introducing policy instruments that support deploying RETs. Notably, the number of countries that have implemented policies in some form to deploy RETs on either the national or sub-national level has nearly doubled in the short time frame from 2005 to 2010 (REN21 2009).

Numerous primary deployment policies are available, including both public financing support instruments and a wide range of regulations that incentivize private sector investments in RETs.[6] With respect to regulations related to employing alternative forms of electricity, the literature distinguishes between quantity-driven policy instruments and price-driven policy instruments (IPCC 2011).

Among quantity-driven instruments, quota obligation systems combined with so-called tradable green certificates (TGCs) are used most widely (REN21 2009). In this system, governments impose a minimum share of electricity that needs to be generated from renewable energy sources. Electricity producers receive TGCs for the amount of electricity they generate using renewable energy sources, which they can sell and buy on exchanges to meet their obligations. The interaction of supply and demand determines the price of the certificates (Mitchell et al. 2006).

The most prominent form of price-driven instruments are feed-in tariffs (FITs). A FIT guarantees the level of remuneration that renewable electricity producers receive for each unit they produce—irrespective of the prevailing market price for electricity. This fixed payment can represent either the total remuneration for producers or constitute a premium in addition to electricity market prices (Couture & Gagnon 2010; Schallenberg-Rodriguez & Haas 2012). In addition, regulators usually guarantee both network connection and electricity off-take. In most countries, regulators choose to differentiate FITs by RET, setting different tariffs for each type of RET. Indeed, sometime different tariffs

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[6] See Table 11.2 in the *Special Report on Renewable Energy Sources and Climate Change Mitigation* for a comprehensive listing of available policy instruments (IPCC 2011, p.890 Table 11.2)

are even established for different types and sizes of power plants within a single RET (BMU 2012).

A scientific debate has revolved around the question of which available primary support policies are most appropriate for deploying RETs (Rickerson et al. 2007; Cory et al. 2009). Saidur et al. (2010) provided a comparative review of energy policies for deploying wind power. The decisive parameters in these comparative assessments are usually effectiveness; that is, the degree to which defined expansion goals can be met by using a certain type of primary support mechanism and (cost)efficiency; that is, how much financial support is needed per unit of renewable energy produced (De Jager & Rathmann 2008). With regard to efficiency, some assessments that employ classic economic theory claim that obligation systems with TGCs should yield higher social welfare (Tamás et al. 2010; Palmer & Burtraw 2005) or at minimum, very similar outcomes if TGC prices are equal to FIT levels (Sims et al. 2007). Others have pointed out that this result only holds in the absence of market imperfections (Menanteau et al. 2003; Finon & Perez 2007; Couture & Gagnon 2010). In reality, however, market imperfections such as transaction costs, lack of knowledge about novel technologies, and the market power of incumbent energy utilities are abundant (Jensen & Skytte 2002; Verbruggen 2004).

Empirical evidence from many countries suggests that FITs are the most efficient and most effective primary policy mechanism that will spur rapid deployment of RETs (Ringel 2006; Stern 2007; Lipp 2007; Ragwitz et al. 2007; Fouquet & Johansson 2008; Dong 2012). The less dynamic and more costly deployment that occurs under quota obligation systems is attributed to higher levels of financial risk for investors that stem from price volatility and the lack of off-take guarantees (Butler & Neuhoff 2008; Mitchell et al. 2006; Doherty & O'Malley 2011).

Despite the consensus favoring FITs, the question of quantity-driven versus price-driven policy instruments is less absolute than one would think. Empirical evidence has also revealed successful quota obligation systems and ineffective FITs systems (Sawin 2004). Furthermore, more and more in practice, the two systems are designed such that each system emulates the respective advantages of the other.

1.4.2 Investigating implementation details and enabling regulations

On the one hand, certificate obligation systems can be implemented with floor prices and price ceilings. The former threshold limits investor risk by reducing price volatility, whereas the latter helps keep total costs to society controlled (Doherty & O'Malley 2011; Soderholm 2008). By employing these design features, quota obligation mechanisms are less susceptible to pure market forces and instead assume some characteristics of price-driven support schemes.

On the other hand, policy makers increasingly consider design features for FIT mechanisms that incorporate market elements. Premium price models, for example, increase exposure to market price volatility (Couture & Gagnon 2010; Claire Kreycik et al. 2011). Lesser and Su (2008) suggested a FIT design based on both fixed-capacity payments and market-based electricity payments to facilitate greater economic efficiency. German regulators have also devised a way to establish market-based feedback to the FIT system by linking the degression rates for the solar PV FIT to market dynamics. The amount of installed capacity in one period determines the rate at which FIT degresses in the next period (de Jager et al. 2010). Just recently, the German government proposed a revision to solar PV tariffs such that the fixed FIT only applies to a fraction[7] of the produced electricity (Photovoltaik-Magazin 2012). Producers must then consume the remainder themselves or sell it according to market conditions.

Hence, the specific way deployment policies are designed and implemented is crucial for understanding their impact on market actors; indeed, the devil is in the details. This was first recognized by Wiser and Pickle (1998), who highlighted the impact of policy design choices on financing RETs (Wiser & Pickle 1998). Many others have since then highlighted the importance of including implementation details in deployment policies (Menanteau et al. 2003; Ringel 2006). Haas et al. (2011) conducted a comparative study on the historic use of renewable energy promotion strategies in Europe and concluded, *"It is not all about the common question of feed-in tariffs vs. quota systems based on tradable green certificates, but more about the design criteria of implemented RES-E support schemes."* (Haas et al. 2011, p.1003). Similarly, the IPCC (2011) maintains that *"Policy design and implementation play an important role in determining how well these policy options measure up against the various criteria, and governments are continuing to adjust details and to learn how these policy options might meet changing needs."* (p. 906).

Hence, it seems that high-level analyses of primary deployment policies are insufficient to generate a thorough understanding of the true drivers of RET deployment. Researchers

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[7] 85 to 90%, depending on installation size.

can add valuable insights by scrutinizing the details of how policies are implemented. Furthermore, a variety of complementary renewable energy policies and regulations conducive to investment environments require attention as well. These include instruments targeted at reducing financial and investment risks, facilitating planning and permitting procedures, regulating grid access, and enabling capacity and knowledge building (IPCC 2011). Each of these secondary aspects can be a crucial success factor in deploying RET. For example, provocatively speaking, well designed deployment policies that promise attractive return rates are likely to fail if high levels of corruption exist among the local permitting authorities. Or, the best primary incentive mechanisms for developing wind power will not effectively motivate companies to expand capacity if the grid access regulations prove prohibitive.

Recently, researchers have started to investigate the impact of such enabling regulations. Analyzing developing wind power farms in Spain, Iglesias et al. (2011) showed that lack of coordination between different administrative levels, intransparency permitting procedures, and the lack of homogeneity across regions can lead to uncertainty for investors and increase transaction costs. Similarly, others have shown how the structure of permitting and planning procedures for offshore wind power installations in Sweden (Soderholm & Pettersson 2011), Germany, and the US (Portman et al. 2009) influence the speed and efficiency of deployment. Regulating grid access for renewable development projects is another important framework condition for deploying renewable energy (Klessmann et al. 2011; Prässler & Schächtele 2012). Alagappan et al. (2011) found that markets where policy makers conduct anticipatory transmission planning and where developers do not have to bear the costs of transmission interconnection are more successful in deploying RETs than those that do not (Alagappan et al. 2011). Notably, the scientific literature still lacks insight into financing support instruments that can complement primary deployment instruments. However, grey publications point out the importance that preferential financing programs have had in the past (UNEP 2008; Project Catalyst 2009).

To conclude, it is the specific implementation design of primary support mechanisms, combined with suitable secondary enabling policy measures, that determines how policy regimes induce rapid and sustained deployment of renewable energies. Comprehensive approaches to renewable energy policy seem promising for inducing investment. Hence, some questions emerge: Which enabling policy measures are needed in which context?

How can regulations that govern developing processes of RET projects be tailored to eliminate bottlenecks to deploying RET? One way to approach these questions is to adopt the perspective of the actors that realize RET deployment: developer companies and investors.

1.4.3 Adopting a developers' perspective

Companies that develop RETs work at the nexus of the political arena and financial investors, effectively linking government targets on RET expansion expressed in form of deployment policies with the capital funds needed to turn those targets into reality. In that position, they are crucial intermediaries who can help addressing the lack of *"[…] dialogue between policy makers and the whole spectrum of financial sector organizations."* (ECF 2011, p.5)

They act on existing incentive schemes, secure the needed investment funds, and manage the construction of the renewable energy power plants. When designing energy policies, policy makers should therefore consider how these policies affect developers and investors. Langniss (1996) captured this nicely when he succinctly stated: "*Supporting the dissemination of RET means supporting people, not technologies. [Therefore], support mechanism have to be adapted to people, not to technologies."* (Langniss 1996, p.1112)

Academics researching renewable energy policy adopted both the investors' and developers' perspective as early as the 1990s. Langniss (1996; 1999) was the first to differentiate different types of investors according to their motivation, level of risk aversion, and financial capabilities. He highlighted the importance of tailoring support policy instruments to meet the requirements of each specific type of investor. Wiser et al. (1997) urged policy makers to acknowledge the challenges that developer companies face in financing renewable energy projects. Dinica (2006) developed a conceptual framework that remains instrumental to structuring the investors' perceptions of risk and return related to RET projects. Adopting the investors' perspective is especially helpful for investigating the risk dimension to developing renewable energies, because this is more difficult to capture with economic modeling approaches. More recently, grey literature has contributed to understanding the impact of policy design on types of clean energy investors and project developers (De Jager & Rathmann 2008; Hamilton 2009). Bürer and Wüstenhagen (2009) were among the first to provide empirical evidence on the investors' and developers' preferences for various types of generic policy mechanisms.

Despite these advances, there is still a lack of understanding of the link between renewable energy policies and the decision-making processes of investors and developers. Wüstenhagen and Menichetti (2012) concluded that *"The empirical evidence about how policies and their risk are actually perceived by investors and project developers has been limited so far"* (p. 3), and they called for further research adopting the investors' perspective.

The research in this dissertation will follow that call, adopting a developers' perspective to assess renewable energy policies.

For the context of this dissertation developers are defined as companies that plan, design, and construct the wind park, whereas investors provide capital to finance it. In practice, the two roles often coincide, because many developer companies also invest capital and remain owners of (or part of) the wind power plant. This is particularly true for offshore wind power where non-energy companies such as financial and institutional investors still hesitate to become engaged. The two groups differ, however, in the extent of their knowledge: Whereas pure investors usually have a high-level understanding of the key aspects of development, they essentially only need to know the basic financial and operational parameters of the wind power asset. Developer companies are more closely involved in all the processes that lead to realizing the wind park, including collaborating day-to-day with regulatory authorities. Thus, developer companies have more knowledge on the concrete barriers to developing wind power. For example, investors need to know *how long* the permitting procedure requires and how to finance the respective cash flows. Developer companies will have more detailed knowledge on *why* the duration takes a long time and *how to improve* it.

This additional insider knowledge is the reason developer companies are the primary target group for the research in this dissertation.

1.5 Research objective

The literature discussion above yields three basic conclusions. (1) Most renewable energy technologies are still dependent on support policies. (2) The design of primary deployment policies, the specifics of how policies are implemented, and an array of complementary regulatory measures determine how successful policy regimes are at inducing efficient and effective deployment of RETs. (3) Conducting empirical research from a developers' perspective enhances the understanding of how renewable energy policies impact deployment dynamics. These insights derived from the literature guide the objective of this dissertation.

Taking onshore and offshore wind power as explorative research cases, the objective of this dissertation is

- to empirically investigate which policy measures are needed to overcome extant barriers to wind power development;
- to determine how these policy measures can be designed efficiently to deliver maximum value to different types of developers of wind power projects; and
- to derive insights that are relevant and actionable for policy makers.

These questions shall be investigated by providing empirical evidence gathered from complimentary research cases on onshore and offshore wind power. Onshore wind power, on the one hand, is the largest RET in terms of installed capacity and cumulated investment. It is a suitable research case representing mature RETs, with established regulatory frameworks governing the deployment processes. Insights on onshore wind power will be useful for driving the deployment of other RETs as they mature. Offshore wind power, on the other hand, represents a novel RET, characterized by short operational track records, an immature industry and less standardized permitting procedures. Thus, it can provide important learnings of how to drive deployment of nascent RETs. Furthermore, there is little scientific literature on developing offshore wind power despite the great promise that the vast resource potential of offshore wind power holds for the decarbonization of European energy systems. An additional objective of this dissertation is therefore

- to add insights on how regulators can best facilitate the developing of offshore wind power.

Three separate research studies have been conducted to deliver on these objectives (see Table 1).

Table 1
Overview of Research Studies

	Research study	Technology	Research interest
I	Analyzing Policy Support Instruments and Regulatory Risk Factors for Wind Energy Deployment—A Developers' Perspective	Onshore wind power	▪ Preference structure of developers for various policy attributes and development conditions ▪ Difference in preferences between various developer groups
II	Developing Offshore Wind Power—Developers' Assessment of Key Barriers and Regulatory Influence in the UK and Germany	Offshore wind power	▪ Barriers to developing offshore wind power ▪ Impact of policies and permitting regulations on developers ▪ Factors determining perceived attractiveness of policy regimes in the UK and Germany ▪ Differentiation of types of developer companies
III	Comparison of the Financial Attractiveness among Prospective Offshore Wind Parks in Selected European Countries	Offshore wind power	▪ Profitability prospects of offshore wind power parks in Europe ▪ Impact of both policy regimes and geographic conditions on the financial attractiveness of offshore wind parks in Europe

In a first step, Study I determines the regulatory attributes that are most decisive for developing onshore wind power. It then quantifies and measures the utility values that developers place on varying degrees of these attributes. It derives recommendations for policy makers on how to improve speed and efficiency of developing onshore wind power projects. Finally, Study I also provides insights on the differences in preference structures with respect to different geographies and different types of developer companies.

Study II investigates the existing barriers to developing offshore wind power and asks which measures policy makers and regulatory authorities can take to eliminate them. Furthermore, the findings highlight in how far different regulations affect various types of developer companies and draws insights from contrasting the policy regimes in the UK and Germany.

Lastly, Study III takes a different angle at determining the perceived attractiveness of policy regimes. Looking through the eyes of financial project managers, it scrutinizes the profitability prospects of designated offshore wind power locations. The decisive parameters incorporated in the analysis of a set of ten different scenario areas are site-specific wind resources, distance to shore and water depth as well as prevailing policy conditions.

Figure 3 illustrates the underlying research framework of this dissertation. It depicts how the study foci tie in with the various objectives research objectives stated above.

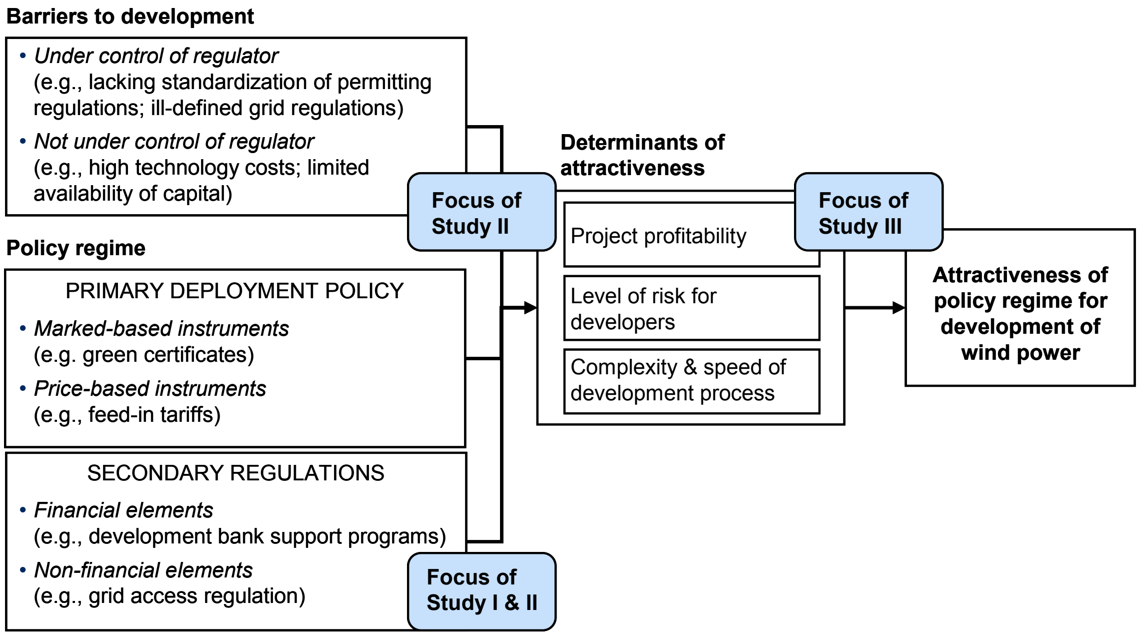

Figure 4: Research framework of dissertation and research foci of individual studies

The framework shows how developer companies perceive the attractiveness of a given policy and investment regime. In this framework, the primary deployment policies and secondary regulations address the barriers that impede the development of wind power. The interplay between barriers and policy regulations yield the conditions under which market participants can drive developing wind power. The studies have shown that developers see three factors as key determinants of attractiveness: the expected profitability of a project, the perceived level of risk that developers have to take, and the complexity and speed of development processes.

All three studies touch upon all of these aspects, albeit with varying foci. In order to differentiate, Figure 3 indicates the respective focal points of each of the studies. Whereas Study I concentrates on scrutinizing the details of the secondary regulations, Study III emphasizes on overall financial attractiveness based on project profitability. The scope and depth of Study II is all-encompassing as it investigates all of the framework’s elements in depth. It particularly pays attention to determining how the combination of barriers and policy regulations channel into the determinants of attractiveness.

1.6 Methods

This dissertation's findings are based mainly on empirical research. The dissertation comprises three distinct research studies that employ three different research methods. These include (1) a large-scale, quantitative, adaptive choice-based conjoint analysis; (2) a qualitative analysis based on in-depth expert interviews and content analysis; and (3) a numeric economic model analysis based on discounted cash flows (see Table 2).

To answer the above-described research questions, a large set of novel empiric data was generated from field research. It includes a rich, quantitative data set with 4,749 choice decisions from 119 participants as well as insights from expert interviews with 41 interviewees. Furthermore, the financial parameters for 70 designated offshore wind power development locations in Europe have been modeled by using individual geographic conditions and historic wind speed data for each location.

Table 2:
Overview of Employed Research Methods

	Research study	Method	Data	Scope
I	Analyzing Policy Support Instruments and Regulatory Risk Factors for Wind Energy Deployment—A Developers' Perspective	Qualitative and quantitative ▪ Phase 1: Expert interviews ▪ Phase 2: Adaptive choice-based conjoint analysis	Novel ▪ 24 interviews ▪ Preference data of 119 participants ▪ 4,749 choice decisions	Europe USA
II	Developing Offshore Wind Power—Developers' Assessment of Key Barriers and Regulatory Influence in the UK and Germany	Qualitative ▪ Expert interviews ▪ Triangulation with external data sources	Novel ▪ 13 interviews (17 participants)	UK Germany
III	Comparison of the Financial Attractiveness among Prospective Offshore Wind Parks in Selected European Countries	Quantitative ▪ Economic modeling based on discounted cash flows	Available ▪ NASA wind resource data ▪ Literature on costs and remunerations	Selected EU countries (B, DK, FR, GER, UK)

The process that leads to developing RET projects is complex and involves many different actors. To build a comprehensive understanding of the drivers and barriers to this process, it is therefore beneficial to analyze the process using multiple approaches. Table 2 shows how the three research studies in this dissertation span a spectrum of research methods, different data sources and methods to capture statistics and insights, and the various geographies examined. Note that the first study scrutinizes onshore wind power, whereas the second and third studies deal with offshore wind power.

The respective strengths of qualitative and quantitative research approaches can complement one another (Steve 2007). Quantitative research approaches usually allow researchers to measure the interrelationships among influencing factors (independent variables) and results (dependent variables) precisely. Quantitative approaches apply holistic, top-down analyses to a basic population of research cases, often aiming at generalizing results. Qualitative approaches, on the other hand, allow for more granular, in-depth analysis of specific research cases. Their strengths lie in discovering a more thorough and more well-rounded set of insights for the specific cases examined. Thus, using both quantitative and qualitative approaches can yield richer results than relying on either one alone (Haggett & David Toke 2006; Stephens et al. 2008). The following section provides a synoptic overview on the methods applied. More detailed descriptions of the applied methods for each study are outlined in the respective chapters of the dissertation.

1.6.1 Adaptive choice-based conjoint analysis

The first study employs adaptive choice-based conjoint analysis (1) to determine which factors constitute barriers and drivers for developing onshore wind power as perceived by developers; (2) to measure the impact that policies and regulations have on developer decision making, and (3) to assess what policymakers can do to increase the attractiveness of policy support systems for wind energy developers.

Conjoint analysis was first applied in the context of marketing research in the early 1970s (Green & Srinivasan 1978; Orme 2007b). Conjoint analysis is founded on the discrete choice theory (Ben-Akiva & Lerman 1985), which assumes that decision makers (e.g., consumers) evaluate choice options such as consumer products by implicitly decomposing them into distinct attributes and placing individual values on those attributes. Hence, the utilities that can be derived from the respective attributes determine the overall value of the product.

This concept has been transferred to the context of energy policy. The main objective is to mimic the real decision-making processes developers and investors use as closely as possible. Here, conjoint analysis offers an interesting analysis approach, because the development decision is not determined solely by preference for a certain primary support mechanism but is driven by multiple variables. The study suggests that conjoint analysis enables researchers and policymakers to deduce the utility of a policy framework when viewed as combined sets of attributes and study how developers implicitly assign value to individual components of the product. Mathematically, this is expressed as:

$$U = \sum_{i=1}^{n} u_i + e \tag{1}$$

where U describes the utility of a chosen policy framework, n is the number of policy attributes, u_i is the part-worth utilities of the attributes i, and e is the unknown or intangible characteristic. Part-worth utilities measure the contribution of attribute levels to the overall utility of a given policy framework.

The attributes, i, can be understood as distinct factors (e.g., the level of remuneration) that influence the developers' decision to develop a wind power project. To design conjoint analyses properly, it is paramount to identify attributes such that they reflect the most important drivers for product selection. Here, we determined the adequate attributes and their respective parameter specifications in a qualitative pre-study. This pre-study included 24 interviews with onshore wind energy experts from developer companies, banks, policymakers, and researchers. Subsequently, we defined six attributes, each with four differentiation levels. As Backhaus (2006) recommended, the attributes are relevant for the development decision and independent from one another such that the utility of an attribute and its levels does not interact with other attributes.

When conducting a conjoint analysis, study participants choose between policy scenarios constructed from hypothetical combinations of attribute levels. The conjoint analysis technique applied in this study is computer-based adaptive choice-based conjoint analysis (ACBC). This means that the survey is adapted during the course of the interview based on the nature of the respondent's previous answers. This adaptive methodology entails several merits: (1) it allows the researcher to capture more information at the individual level than traditional, non-adaptive surveys; (2) it facilitates smaller samples of about 60 participants; (3) it prevents respondents from focusing on paramount attributes and neglecting others; and (4) it decreases the time required to complete the survey, preventing potential information overload or confusion (Sawtooth Software 2007; Shepherd & Zacharakis 1999; Orme 2010).

In total, 1,260 onshore wind energy developers working at different types of developer companies were contacted. The final sample comprised 102 complete data sets, of which 119 data sets could be used for utility calculations.

The collected data were aggregated using hierarchical Bayes (HB) estimation model (Rossi & Allenby 2003; Orme 2007a), which has become the standard estimation method for conjoint analysis (Lenk et al. 1996; Rossi & Allenby 2003; Netzer et al. 2008). The HB model consists of two levels. First, it considers respondents as members of a population of similar individuals where part-worth utilities follow a multivariate normal distribution (Orme 2010). Second, at the same time it preserves each individual's part-worth utilities by employing a linear regression model. Each respondent's utilities are then adjusted in an iterative process (40,000 iterations), so that they reflect the optimal mix of the individual respondent choices and the sample averages (Howell 2009).

The resulting data then built the basis for a range of analyses, including:

- *Part-worth utility estimations*, which show the value of each attribute level;
- *Importance scores*, which measure the influence an attribute exerts on the overall utility of developers;
- *"Unacceptables,"* which identify minimum requirements for wind power development, revealing non-compensatory decision-making in the face of very high risks or very low remuneration levels;
- *Cluster analyses,* which highlight differences among regions and developer types; and
- *Preference simulations*, which allow scenario-based, region-specific policy analyses.

1.6.2 Qualitative content analysis based on expert interviews

The study on developing offshore wind power employs a qualitative research approach. The choice here has two benefits. First, qualitative research is more adequate for accommodating the high complexity of offshore development projects and allows for a more granular understanding of the drivers and barriers to offshore development (Eisenhardt 1989; Kohlbacher 2006; Gläser & Laudel 2009; Mayring 2010). Second, because the offshore wind power industry is still in its infancy, only a limited number suitable study participants possess both the required knowledge and the required level of experience. Thus, for this study, quantitative approaches that aim for statistically reliable findings seemed less promising both regarding the feasibility of generating enough empiric data and regarding the limited validity of potential results.

Following the typology proposed by Gläser and Laudel (2009) the method applied in this second study can be categorized as non-standardized, expert interviews with an interview guide. This approach allows for sufficient flexibility during the interview and, at the same time, ensures comparability of the results. Interview findings are triangulated with additional data sources to probe the reliability of the findings and enhance construct validity of the research approach (Denzin & Lincoln 2005; Yin 2003). The interview guide is designed to meet the four principles of (1) reach, (2) specificity, (3) depth, and (4) personal context, concepts that are suggested in the literature (Merton & Kendall 1979; Hopf 1978).

The literature on qualitative research provides many suggestions of how to construct the interview sample in order to generate valid results (Morgan 1988; Eisenhardt 1989; Patton 2002; Gläser & Laudel 2009; Flick et al. 2010; Merkens 2010). The study presented in this dissertation goes beyond most of these suggestions by constructing a high-quality sample with respect to (1) the expertise of the selected interview partners, (2) selecting suitable companies, and (3) the breadth and representation of current offshore development activities in the target countries. Seventeen interview partners from 13 offshore wind power development companies participated in the study. These companies represent more than 75% of the market share of offshore wind parks (OWP) being developed in Germany (Wind:research 2011) and companies that are active in more than 70% of the development Round 1 and 2 project areas in the UK (Scottish Enterprise 2010).

All interviews were conducted either in person or via telephone and were recorded on tape when the interviewee consented. All sound files were transcribed according to written interview protocols, which were collected in a central database as Gibbert et al. (2008) suggested. The interview protocols established the foundation for the content analysis.

Content analysis has been established as a research method in the social sciences for more than 60 years, dating back to Berelson's methodological treatise "Content analysis in communication research" in 1952 (Berelson 1952). Qualitative content analysis is not a standardized textbook tool (Mayring 2010, p.49). Still, it usually contains three basic techniques: synopsis, structuring, and explication. All three techniques are employed in analyzing the data for this study. The process includes techniques such as semantic coding, topical comparisons (Meuser & Nagel 2009), and triangulation with external data sources.

The resulting set of condensed, color-coded, and regrouped interview summaries built the basis for the discussion of results, allowing for (1) differentiating opinions from different respondent groups, and (2) indicating the quantitative level of homogeneity for each of the findings.

1.6.3 Numeric economic modeling

The results of the first two studies rely mainly on the input from developers of wind power projects. This is a valid approach because this dissertation's overarching research questions specifically focus on the developers' perspective.

From a scientific prudence standpoint, however, a certain bias and subjectivity on behalf of the respondents cannot be dismissed despite data triangulation. Whereas the ACBC analysis in the first study is less susceptible to subjective opinions because choice experiments yield preference utilities indirectly, the participants of the second (qualitative) study may or may not have political agendas when answering the research questions. Thus, the aim of the third and last study is to complement the above studies by adding a robust analysis based on objective facts rather than stated preferences and opinions.

The third study applies an economic analysis based on a standard discounted cash flow (DCF) model to assess the financial attractiveness of offshore development conditions in Belgium, Denmark, France, Germany, and the UK. The model includes all pertinent costs and revenues of OWPs. It determines the internal rate of return (IRR) and uses this result as final attractiveness indicator for comparing the location scenarios of 10 different OWPs. Formally, the IRR is derived by calculating the discount rate that sets the net present value of the project to zero:

$$NPV = \sum_{n=0}^{N} \frac{C_n}{(1+r)^n} = 0 \qquad (2)$$

where r is the discount rate; *n* is a given year, *N* is the total number of years, and *C* is the cash flow in a specific year. For the comparison exercise, the IRR is an adequate and objective profitability indicator, because it does not require assumptions on discount rates (Brealey et al. 2010).

Study 3's analysis is conducted on a simple national economic basis. This modeling approach deliberately excludes company-specific factors such as taxes, depreciation effects, or financing structures in order to facilitate robust comparability of the fundamental, scenario-specific profitability drivers. Such factors would dilute comparability because companies (1) have certain degrees of freedom with respect to applying accounting, depreciation, and evaluation methods; (2) differ in their financing abilities, which affects taxable income: and (3) are subject to dissimilar national or regional tax laws.

As with any model, the results are only be as good as the ingoing assumptions. Extensive research of the scientific literature, industry reports, and personal interviews was undertaken to arrive at the latest, state-of-the art data on cost structures, revenue potential, and wind resources. All assumptions have been verified with industry experts and other scientists. Cost assumptions are adjusted for real geographical parameters (water depth and distance to shore) of the OWPs—a differentiation that has not yet been addressed in the literature. Revenue assumptions are a detailed reflection of current respective national electricity market prices and regulations regarding support schemes. Finally, the assumptions for wind resources use location-specific parameters for 70 designated OWP sites based on a 10-year mean wind speed derived from NASA satellite data. The robustness of the model regarding the most important input parameters has been checked with several sensitivity analyses.

- Filled with these data, the model is used for a range of analyses, including:
- Comparing profitability values across ten location scenarios;
- Comparing cost structures across ten location scenarios;
- Running simulations that show the impact of national policy regulations on the attractiveness of scenarios; and
- Running a simulation of a future scenario that estimates the potential of technology advancements, cost reductions, and operational improvements.

1.6.4 Limitations of applied methods

The specific limitations of each applied method are described in the chapters related to each study.

One commonality across all studies, however, is that all of the analyses are conducted from the developers' perspective. Although this is in line with the objective of this work and yields detailed insights, it constrains the understanding of the dynamics of developing wind power to a specific angle. Energy policymakers, however, need to adopt a multistakeholder perspective and incorporate additional aspects when crafting policy instruments. Such aspects include the distribution of rents between investors and electricity consumers or tax payers (Bergek & Jacobsson 2010), the technical challenges of integrating renewable energy sources (Ibrahim et al. 2011; Zahedi 2011; Purvins et al. 2011), the implications for grid infrastructure (Schaber et al. 2012a; Schaber et al. 2012b)(Zahedi 2011; Purvins et al. 2011), environmental protection (Saidur et al. 2011; Kamil 2002), and arguably considerations for industry development and job creation (Lewis & Wiser 2007a; Lewis & Wiser 2007b).

Thus, when interpreting the results of the three studies, it is important to keep the perspective of the analysis in mind. The findings should primarily help to generate a deeper knowledge on how policy schemes and implementing specific policy instruments affect developers and investors.

Furthermore, the first two studies rely on indirect and direct input from developers; that is, they use individual *perceptions*. It would be useful to come up with a way of linking stated preferences & barriers to revealed preferences (Angeliki 2008; Brownstone et al. 2000).

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Chapter 2

Analyzing Policy Support Instruments and Regulatory Risk Factors for Wind Energy Deployment—A Developers' Perspective

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Analyzing policy support instruments and regulatory risk factors for wind energy deployment—A developers' perspective

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ABSTRACT

A transition to a renewable energy system is high on the policy agenda in many countries. A promising energy source for a low-carbon energy future is wind. Policy-makers can attract wind energy development by providing attractive policy frameworks. This paper argues that apart from the level of financial support, both the risks stemming from the regulatory environment (legal security, administrative process and grid access) and the ability to finance projects play a critical role in determining the attractiveness of the development environment. It sheds light on how project developers trade off these different aspects and to what extent the attractiveness of a certain policy framework increases with the introduction of specific measures. Conjoint analysis is employed to provide empirical evidence on the preference of wind energy developers in the EU and the US. The analysis shows that developers' preferences are very similar across the studied regions and for different types of developers. Which policy measures could be most valuable depends on the specific existing environment. In some southeastern European countries, a reduction of administrative process duration may yield the highest utility gains, whereas, in the US, improvements in grid access regulation and an increase in remuneration levels may be more effective.

1. Introduction

Although the overall share of renewable energy in global electric power supply is still low, there is significant growth in some subsectors. A relevant indicator for this trend is the investment flow in new power stations. In 2008, global power generation investment in renewable power technologies exceeded investment in fossil-fueled technologies for the first time (Hohler et al., 2009). Among the various renewable energy sources, wind energy is one of the most prominent: in 2009, it accounted for 64% in the EU and 90% in the US of all new renewable generating capacity and for 39% of all new US and EU electric generation capacity (Bloem et al., 2010; EWEA, 2010a; Wiser and Bolinger, 2010). While the cost of wind energy has come close to grid parity in locations with consistently strong winds, its growth has been, and still is, largely driven by policy incentives.

Among the most prominent instruments to support wind energy and other renewable energy technologies are those that subsidize revenues from electricity sales, for instance feed-in tariffs and renewable obligation certificates. However, attractive return levels alone are not sufficient to effectively drive the diffusion of wind energy. The OECD and the IEA find in a report on the wind energy policies effectiveness in OECD and BRICS[1] countries (OECD/IEA, 2008) that "[b]eyond some minimum threshold level, higher remuneration levels do not necessarily lead to greater levels of policy effectiveness" (OECD/IEA, 2008, p. 17). They argue that high non-economic barriers are one reason for this result. Therefore, financial support schemes need to be complemented by policy measures that address non-economic barriers to deployment (OECD/IEA, 2008; EWEA, 2010b; Valentine, 2010).

The question is which deployment barriers are most relevant and how policies can help to remove them. According to the IPCC, "[b]*arrier removal* includes correcting market failures directly or reducing the transactions costs in the public and private sectors by, for example, improving institutional capacity, reducing risk and uncertainty, facilitating market transactions, and enforcing regulatory policies" (IPCC-WGIII, 2007, p. 77). A substantial body of literature has identified a broad variety of such barriers and development risks for wind energy. They include administrative hurdles such as lengthy, ill-structured authorization and permitting procedures (OECD/IEA, 2008; EWEA, 2010b); nontransparent and costly procedures for grid connection (RETD, 2006; Swider et al., 2008; EWEA, 2010b); strict environmental regulations

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(EWEA, 2010b); support policy instability with sudden policy changes and stop-and-go situations (Wiser and Pickle, 1998; Meyer, 2007; Barradale, 2010); and lack of social acceptance (Jobert et al., 2007; Nadaï, 2007; Wüstenhagen et al., 2007).

To understand how these factors influence decision making on a company level and how the resulting risks for deployment can best be mitigated, it is useful to study them from an investors' perspective. Such a perspective was adopted by academics as early as the nineties. Wiser et al. (1997) identify perceived resource and technology risks and high support policy risk as the main hurdles that renewable energy project developers face in obtaining financing. Langniss (1996) categorized different types of investors and recognized that the type of support and taxation scheme has implications on which type of investor will be attracted. Dinica (2006) proposes to adopt an investor perspective and shows conceptually how developers evaluate the ratio of risks and profitability associated with renewable energy projects. Bürer and Wüstenhagen (2009) emphasize that the understanding of investor perceptions may provide policy-makers with the opportunity to leverage private investment to reach renewable energy targets. All these studies provide valuable insights for a better understanding of the drivers of development and diffusion of new wind energy capacity. The applied methodologies have been either conceptual analyses or qualitative case studies. The maturing of markets with an ever growing number of companies engaged in wind energy development now allows this paper to employ a large scale quantitative empirical analysis. The paper largely builds on the findings of existing literature and intends to add to them in three ways. First, it employs a relatively novel methodology to energy policy research: multivariate adaptive choice-based conjoint analysis. The paper suggests that conjoint analysis could be a helpful scenario tool for estimating potential effects of specific policy measures on wind energy project developers' investment behavior. Second, the paper provides a quantitative, empirical dataset of developers' preferences. The preference data quantifies how much value specific measures provide to developers. Third, it gives some indication of how these findings differ among different groups of developers and across different regions within the two most mature wind energy markets: the EU and the US.

The paper is structured as follows. The next section specifies the method by introducing conjoint analysis and explaining the experimental design as well as the data analysis approach. Section 3 describes the study sample. Section 4 presents and discusses the results. It includes a breakdown of developers' preferences for the studied attributes and levels, simulations of the effects of policy measures on developers' preferences in specific investment environments and an analysis of preference differences between different subgroups of project developers. Finally, section five concludes by highlighting main findings, outlining policy recommendations, indicating the limitations of this study and making suggestions for further research.

2. Methodological approach and experimental design

2.1. Conjoint analysis

Conjoint analysis methods are based on work done in the sixties by the mathematical psychologists and statisticians Luce and Turkey (1964) and were introduced into marketing research in the early 1970s (Green and Srinivasan, 1990; Orme, 2007b). The key characteristic of conjoint analysis is that respondents evaluate product profiles composed of multiple conjoined elements (attributes). The main objective is to mimic real decision-making processes as closely as possible. The respondents' evaluation of the combined sets of attributes (the product scenarios) makes it possible to calculate the preference scores that they implicitly assign to individual components of the product.

Conjoint analysis is based on the Discrete Choice Theory (Ben-Akiva and Lerman, 1985; Train, 2009). Microeconomic consumer theory and utility maximization provide the first foundation to discrete choice theory. However, it is not possible to completely describe any option's utility in terms of its attributes; there will always be some unknown or intangible characteristics, which may provide additional utility. Random Utility Theory (Mansky, 1977) is thus the second foundation of discrete choice theory and the direct utility function of a person can be broken down into observable (deterministic) and unobservable (stochastic) parts.

The utility of a policy framework can be described as

$$U = \sum_{i=1}^{n} u_i + e \tag{1}$$

where U is the utility of the chosen policy framework, n the number of policy attributes, u_i the part-worth utilities of the attributes i, and e the unknown or intangible characteristic.

The probability that a project developer k chooses the policy framework j from choice set C_t is given by the following (adapted from Ben-Akiva and Lerman (1985)):

$$P_{kj} = \Pr(U_{kj} \geq U_{km}; \forall j \neq m; j,m \in C_k) \tag{2}$$

where P_{kj} is the probability that a project developer k chooses the policy framework j, U the utility of the policy framework alternatives, j the chosen policy framework alternative, m the all other alternatives, and C_k the choice set available to the project developer k.

The conjoint analysis technique applied in this study is adaptive choice-based conjoint analysis (ACBC). ACBC captures more information at the individual level than traditional, non-adaptive surveys and may be used even with small samples of about 60 participants (Shepherd and Zacharakis, 1999; Orme, 2010b). ACBC prevents respondents from focusing on paramount attributes and neglecting others as it recognizes such attribute levels and then focuses in subsequent questions on the remaining ones. Hence, the questions generated during the course of the survey are based on factors that are identified as being relevant to the survey respondent (Sawtooth Software, 2007). Additionally, the customized approach decreases the time required to complete the survey and prevents respondents from potential information overload or confusion (Sawtooth Software, 2007).

2.2. Selection of attributes—investigating the drivers for project development decisions

In this paper, we assume that renewable energy project developers choose their projects' locations by looking for the bundle of attributes that provides the highest utility. In this choice among alternatives, there is an inevitable trade-off between the different attributes, and any attribute change influences the attractiveness of the respective country for the project developer. A higher level of support, for example, increases the utility and thus the attractiveness of a country, whereas longer administrative duration decreases the utility.

In order to determine the relevant drivers for the development decision to investigate in this study, we have (a) screened existing literature that cover drivers of wind energy development and (b) conducted a qualitative pre-study with experts in the field. As mentioned above, studies have shown that developers do not exclusively focus on the level and type of financial support when making the development and siting decision. Risks that are

Table 1
Overview of factors influencing the development decision, not exhaustive. Shaded area shows the focus of this study.

Factors	Controlling entity	Use in study
Policy factors		
Risk factors		
• Administrative approval duration/complexity/transparency	Policy-makers	Included; explaining variable
• Grid access regulation (e.g., access guarantee, priority dispatch/connection costs)		Included; explaining variable
• Legal security (contract enforceability)		Included; explaining variable
• Renewable energy policy stability		Not included
Return factors		
• Level of production-based support (e.g., feed-in tariff, tradable green certificates, production tax credit)	Policy-makers	Indirectly included; "total remuneration" as explaining variable
• Duration of production-based support		Defined in survey as 20 year
• Level of investment based support (e.g., cash grants, investment tax credit)		Included; explaining variable
• Level of financing support (e.g., soft loans)		Included; explaining variable
Organizational and behavioral factors		
• Type and size of developer company	Mostly within sphere of control of developer, some beyond control	No explaining variable but discrimination in results
• Experience with wind development		No explaining variable but discrimination in results
• Knowledge of and attitudes towards energy policy, financial markets and market environment		Not included
• Local/national investment culture		Not included
• Personal factors (e.g. risk propensity, personal networks)		Not included
Market based factors		
• Electricity demand	Mostly driven by markets, only indirectly controlled by policy-makers, however not specific to wind energy	Not included
• Competition		Not included
• Access to local partners and trained employees		Not included
• Price of electricity		Indirectly included; "total remuneration" as explaining variable
• Infrastructure		Not included
• Currency risk		Not included
Wind resource quality	None	Defined in survey as "high wind quality location that yields an average capacity factor of ~25% (~2200 full load hours)"

inherent to the development process and lead to uncertainty and higher costs are also decisive. Nontransparent, lengthy processes for acquiring building consent and grid connection permits can be major barriers to the development of new wind energy plants and their integration into the energy markets (Johnston et al., 2008; EWEA, 2010b). Table 1 shows an overview of the most important factors influencing the decision-making process of wind energy developers.

The goal of the study is to measure the impact that policy settings and regulations have on developer decision making and to assess what policy-makers can do to increase the attractiveness of the policy support system for wind energy developers. We therefore focus on factors that can be influenced by policy-makers. These include all aspects, which involve some sort of governmental action, or at least the possibility of such (Butler and Joaquin, 1998).

Besides these regulatory factors, there are many organizational and behavioral factors that influence the choices of project developers. These include, for instance, expertise, fast, and efficient development processes at the developer's end, procurement of turbines, choosing turbines that best match the wind regime, etc. These factors are not included as explaining variables in the study because they are competencies incumbent on the developers themselves. Also, factors that are largely beyond the control of wind energy policy-makers and developers are excluded as explaining variables of the study. These are mostly market based factors such as access to local partners and trained employees, competition levels, currency risks or existing infrastructure.

Analogously, the quality of the wind resource was excluded as an explaining variable, but expectations regarding the quality of the wind resource were homogenized among respondents.[2]

To verify that we included the most relevant aspects (attributes) in the conjoint analysis and to determine which parameter specifications (levels) were most appropriate for each attribute, we conducted 24 interviews with wind energy experts in Europe and the US. The sample included small, medium and large wind energy developers, utilities with their own development activities, development banks, policy-makers, and researchers in the field of wind energy policy. The interviews were semi-structured, following interview guidelines.

Based on the expert interviews, six attributes and relevant levels were chosen to reflect the current market conditions in the studied regions and included in the ACBC experiment (cf. Table 2). The identified attributes included in the conjoint analysis are both

[2] In order to control expectations about the total number of electricity produced, a disclaimer prior to the survey instructed respondents: "For all of the following questions please assume you want to develop a generic onshore wind energy project of 10 MW at a high quality wind location that yields an average capacity factor of ~25% (~2200 full load hours)." This disclaimer aligns ingoing assumptions about electricity production (2200 h $\times$ 10 MW= 22.000 MW h).

Table 2
Attributes and attribute levels used in the ACBC experiment.

Attributes	Description provided in survey	Attribute levels used in survey
Administrative process duration	Total time to obtain all required permits from first application to final authorization of plant. Not included: time for technical site evaluation, PPA negotiations, construction, etc.	1 year 3 years 5 years 7 years
Legal security	Confidence in contract enforcement and predictability of legal decisions	Not given, corruption possible Given in some cases Given in most cases Given in all cases
Grid access	Arrangements in place to regulate access to transmission and distribution systems.	Access not guaranteed, negotiated on project-by-project basis; Access guaranteed; no priority dispatch (output curtailment likely) Access guaranteed, mostly priority dispatch (minor output curtailment possible); Access guaranteed, priority dispatch (no output curtailment)
Total remuneration	Sum of all income streams related to electricity sales (feed-in tariff, power purchase agreement, tax credit, premium, certificate, etc.) over 20 years.	5 € ct/kW h//7 $ ct/kW h 8 € ct/kW h//11 $ ct/kW h 11 € ct/kW h//15 $ ct/kW h 14 € ct/kW h//19 $ ct/kW h
Credit financing		No support Gov. guaranteed soft loans 0.5% below market rate Gov. guaranteed soft loans 1% below market rate Gov. guaranteed soft loans 1.5% below market rate
Investment cash grants	Non-reimbursable cash payments as percentage of total investment costs.	0% 10% 20% 30%

relevant for the development decision and independent from each other (i.e., the utility of the attribute and the perceived utility of a level should not interact with other attributes) (Backhaus et al., 2006). To avoid unrealistic return level combinations, three prohibitions were included.[3]

"Administrative process duration": Obtaining all permits required to build the wind energy plant is the key to a developer's business. The efficiency of the administration process depends, among other things, on its transparency, on the reliability of permit approvals and on the total number of authorities involved (Strom, 2010). It is impossible to assess all these aspects individually in a conjoint analysis, but they are combined in the total average duration to get final authorization for a project.

"Legal security": Legal security includes overall legal stability, a country's track record as to legal conduct, corruption levels, enforceability of contracts and reliability of business partners.

"Grid access": Grid access is a complex issue that comprises multiple aspects: (1) the capacity of the grid to deal with the quantity and quality of wind electricity, (2) the availability/proximity of access points, (3) the national/regional long term strategy for grid expansion, (4) regulations regarding access guarantee and cost sharing between grid operators and developers, and (5) regulations regarding the dispatch of wind electricity. To concentrate on the issues that can both be directly influenced by policy-makers and have an immediate impact on developers, we chose levels to reflect access guarantee and dispatch regulations.

"Credit financing": Many wind energy plants are debt financed, especially in Europe. In the aftermath of the credit crisis, many developers have difficulties in securing debt financing at attractive prices. Government-backed soft loans are an effective way of providing funds for wind energy development. In Germany, for instance, the "Renewable Energy Program" of the KfW bank is involved in almost 2/3 of all installed wind energy plants (Bickel et al., 2009).

"Investment cash grants": Apart from production-based support, policy-makers can opt to subsidize part of the initial upfront investment of a project. Especially in the US, this is a widely used instrument.

"Total remuneration": The total remuneration describes the total production-based income per kW h. This may include electricity sales (e.g., through power purchase agreements), feed-in tariff, production tax credit, tradable certificates, etc. From the project developers' point of view, the type of income source is less decisive, as long as the sum of all operating income sources is sufficiently high and sufficiently stable. For the survey, we therefore defined this attribute to comprise all sources of income that can be seen as reliably stable for 20 years. This definition of cash inflows renders the study applicable across different policy regimes. It is important to note, that the remuneration level, taken on its own, is not a good indicator of attractiveness. It may often be the most visible feature of a support scheme, but the attractiveness can only be assessed together with associated costs and risks.

2.3. Utility and profitability

The selected study attributes impact "utility", the dependent variable of the study as defined in (1). At the same time, they have direct influence on project profitability. The two concepts are closely linked: project profitability is the monetary target dimension many project developers strive to maximize, whereas utility can be understood as the perceived attractiveness of a set of policy measures. The latter encompasses more aspects because there may be factors that have no impact on profitability but still influence utility. However, measures that improve profitability will generally also improve utility.

Fig. 1 illustrates how the notion of project profitability brakes down into its drivers. The study attributes relate to key profitability drivers, indicated in parenthesis. In the quest to maximize project profitability developers have some elements of this equation under their own control (such as park design, matching turbines to the wind regime, procurement of turbines and other equipment, fast and efficient development processes at the

[3] (1) 14 € ct/kW h//19 $ ct/kW h and 30%; (2) 14 € ct/kW h//19 $ ct/kW h and 20%; (3) 11 € ct/kW h//15 $ ct/kW h and 30%.

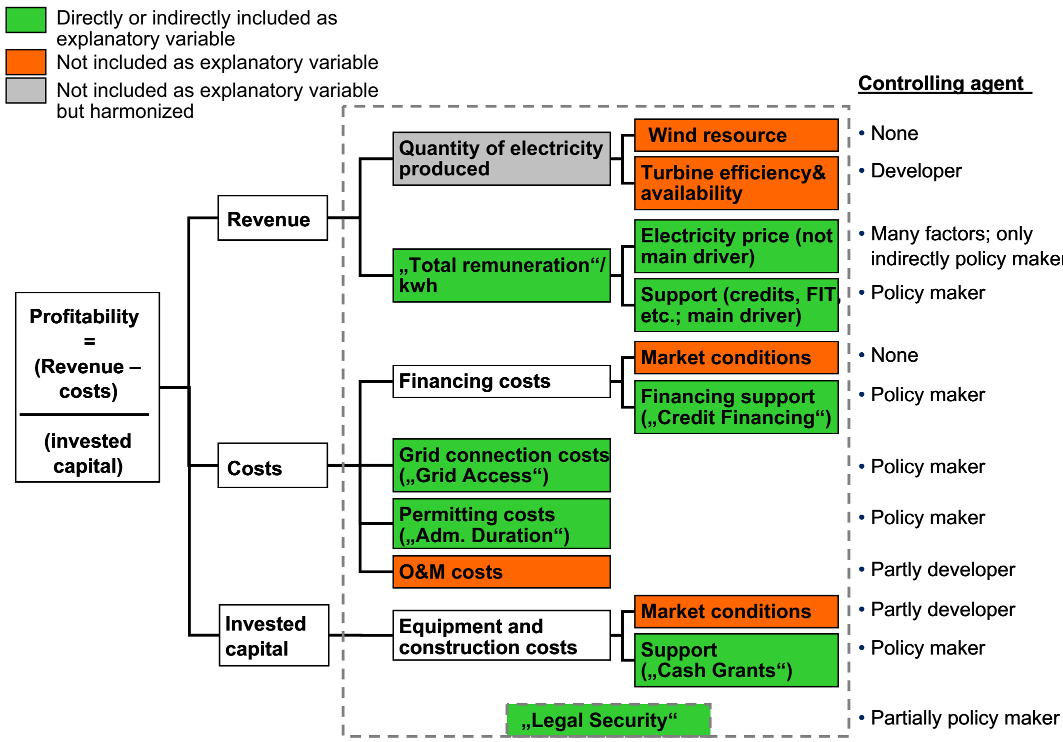
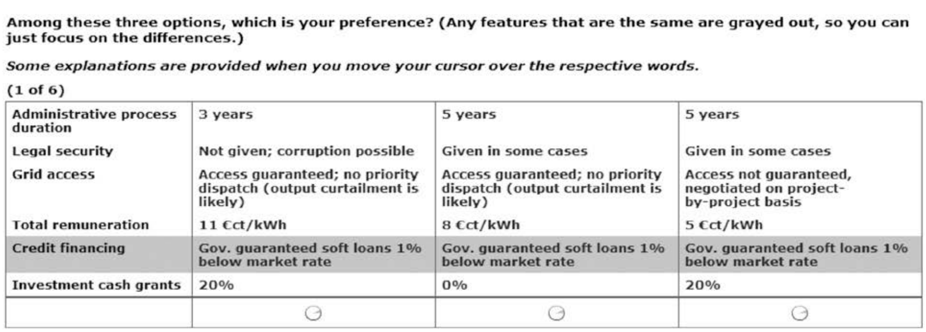


Fig. 1. Drivers of project profitability and controlling agents.



Among these three options, which is your preference? (Any features that are the same are grayed out, so you can just focus on the differences.)

Some explanations are provided when you move your cursor over the respective words.

(1 of 6)

Administrative process duration	3 years	5 years	5 years
Legal security	Not given; corruption possible	Given in some cases	Given in some cases
Grid access	Access guaranteed; no priority dispatch (output curtailment is likely)	Access guaranteed; no priority dispatch (output curtailment is likely)	Access not guaranteed, negotiated on project-by-project basis
Total remuneration	11 €ct/kWh	8 €ct/kWh	5 €ct/kWh
Credit financing	Gov. guaranteed soft loans 1% below market rate	Gov. guaranteed soft loans 1% below market rate	Gov. guaranteed soft loans 1% below market rate
Investment cash grants	20%	0%	20%

Fig. 2. Screenshot of choice section of ACBC survey.

developer's end, etc.). However, for elements they have not under their control they will look for the best available conditions. These can often be influenced by policy-makers, for instance, by setting attractive remuneration levels, subsidizing investment and/or financing, minimizing costs stemming from grid access regulations, or streamlining administrative procedures. The green boxes indicate where the study attributes relate (directly or indirectly) to these key drivers of project profitability. The attribute "Legal security" cannot be allocated directly to a profitability driver. However, an instable and insecure legal environment has impact on key profitability drivers. It is usually reflected in higher financing costs, it can lead to higher grid connection costs as well as permitting costs and it might also lead to limited enforceability of off-take agreements on the revenue side.

2.4. Questionnaire design

The online survey (http://www.windinvestment.ch) consisted of two parts: (1) the conjoint analysis experiment to analyze the part-worth utilities and importance of different policy attributes and (2) background questions about the participants and the companies at which they were employed. It was designed with Sawtooth Inc. (SSI Web), which is a standard software solution for the design and the analysis of conjoint analysis experiments (Sawtooth Software, 2008).

The ACBC experiment started with screening questions presenting four policy-framework scenarios at a time. Each respondent was asked to indicate whether he/she would consider developing a wind energy project under the indicated conditions. The alternative scenarios were constructed using a factorial random design with an orthogonal set of attributes. This section recognized if respondents used cutoff rules focusing just on a few attributes instead of evaluating the scenarios as a whole. If so, he/she could indicate critical attribute levels as a "must have" (i.e., as an absolute requirement) or as "unacceptable". All further scenarios shown then satisfied those requirements.

In the subsequent choice tasks section, the respondent selected the preferred scenario out of three scenarios previously marked attractive for investment (cf. Fig. 2). The chosen scenarios of each triple then showed up again in subsequent choice tasks until the most preferred scenario was identified.

The conjoint section was concluded by a so-called holdout task. Holdout tasks are not used to estimate part-worth utilities but to assess the quality and performance of the model used for the utility estimations (see Section 4). If the responses to holdout questions can be predicted accurately using estimated part-worth utilities, it lends greater credibility to the model.

2.5. Data analysis approach

The 4749 choices of the 119 respondents (39.9 tasks per person) were used to assess the value of the different attributes and levels. The estimations of the part-worth utilities as well as the preference simulations were conducted using Sawtooth Software, Inc. programs (SSI Web and SMRT). In addition, SPSS 18 was used to do further statistical analysis.

Part-worth utilities measure the contribution of attribute levels to the overall utility, i.e., the influence of a change of the respective variable on the developer's likelihood to develop a specific project. The average part-worth utilities are calculated from the individual part-worth utilities of each respondent, using the hierarchical Bayes (HB) estimation model (Rossi and Allenby, 2003; Orme, 2007a), which has become the standard estimation method for conjoint analysis (Lenk et al., 1996; Rossi and Allenby, 2003; Netzer et al., 2008). Individual utilities allow assessing heterogeneity among customer segments, which is more difficult with traditional conjoint approaches based on aggregated preferences measures (e.g., standard multinominal logit (MNL) (McFadden, 1986)).

HB assumes that the respondent answers choice tasks according to a MNL model. MNL considers the probability of the specific alternative being chosen (P_{kl}) related to the proportion of the total utility for that concept relative to the total utility for all the concepts according to the following formula (adapted from Howell (2009)):

$$P_{kj} = \left(e^{U(j)} \Big/ \sum_{l=1}^{m} e^{U(l)} \right) \quad (3)$$

where P_{kj} is the probability that the developer chooses policy framework j, m the number of alternatives, and l the policy framework alternative.

The HB model consists of two levels. At the upper level, respondents are considered as members of a population of similar individuals (Orme, 2010c). Their part-worth utilities are assumed to have a multivariate normal distribution described by a vector of means and a matrix of variances and covariances. At the lower level, each individual's part-worth utilities are calculated by a linear regression model according to the respondent's choices within the conjoint analysis experiment. Discrepancies between actual and predicted choices are assumed to be distributed normally and independently of one another. With several thousands of iterations (for this study, 40,000 iterations were done), each respondent's utilities are adjusted so that they reflect the optimal mix of the individual respondent choices and the sample averages (Howell, 2009).

Part-worth utilities are interval data and scaled to an arbitrary additive constant within each attribute (Orme, 2010b). It is thus not possible to compare utility values between attributes. Zero-centered differentials (diffs) part-worth utilities are scaled to sum to zero within each attribute, and the sum of the average differences between best and worst levels across all attributes is equal to the number of attributes times 100 (Orme, 2010c). This makes it possible to compare the differences between the attribute levels.

The importance scores of each attribute are calculated taking the range of the attributes' utility values, i.e., the highest and the lowest part-worth utility of each attribute. A bigger range signifies a higher importance (Backhaus et al., 2006). The relative importance of each attribute is calculated using the following formula (adapted from Clark-Murphy and Soutar (2004)):

$$RI_l \ (\%) = \frac{(MaxU - MinU)i}{\sum (Max - Min)i} 100 \quad (4)$$

where RI_i is the relative importance of attribute i, $MaxU$ the maximum utility of attribute i, and $MinU$ the minimum utility of attribute i.

The counts analysis provides insights about the "unacceptable" or "must have" levels and indicates how often specific levels have been chosen in the winning scenario of the choice section.

Preference simulations allow gauging the impact on developers' preferences of certain attribute level changes within specific policy environments (i.e., sets of attribute levels). The simulations estimate the probability that project developers would develop a project in different policy frameworks by summing scaled utilities and applying the following transformation (adapted from Orme, 2010c):

$$p \ (\%) = \frac{e^u}{1 + e^u} 100 \quad (5)$$

where p is the probability of investment, e the constant e, and u the utility of the policy framework in question. Values created by the preference simulations indicate ratio scaled relative preferences.

3. Data collection and sample

The wind energy project developers included in this study are experts who work or have worked for companies engaged in the project development business. These include

- highly specialized, typically small firms whose exclusive business focus is the development of renewable energy projects. Due to the lack of capital or financing, they often sell the project during or after the development process;
- vertically integrated, typically larger firms, who plan, build, own, and operate renewable energy projects.

In total, 1260 wind energy developers active in the US and Europe were contacted individually between April and July 2010. The contact information of the target sample was gathered via personal contacts, wind energy conferences,[4] profiles on professional network websites,[5] collaboration with wind energy associations[6] and publicly available contact information (mainly member directories of associations such as AWEA and RENUK). Where email addresses were available, a reminder was sent after 4 weeks.

The response funnel is shown in Fig. 3. With 102 complete data sets, the final conversion rate was 8.1%. For the regional analysis (Section 4.4), 108 respondents could be used, as they completed the conjoint analysis section and indicated in which countries they were active. The choice data of 119 respondents could be used for the preference calculations as 17 respondents quit the survey only during the background questions.

Table 3 summarizes the sample characteristics. The majority of respondents have 3 or more years of experience with wind energy development. Most developer companies are independent developer or independent power producer companies, are engaged in

[4] EWEC 2010, Warsaw, April 20–23, 2010, and Wind Energy Forum 2010, Davis, May 10, 2010.

[5] www.xing.de; www.linkedin.com

[6] Bundersverband für Windenergie and the Finnish wind energy association supported the study with direct mailing to their members; the American Wind Energy Association and IG Windkraft Österreich published the survey link in member newsletters or websites.

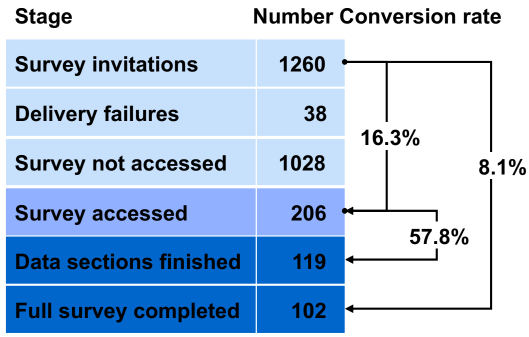


Fig. 3. Response funnel.

Table 3
Descriptive statistics of wind energy project developer in our sample.

Characteristic	Levels	Share (%)
Developer type ($n=105$, multiple choices possible)	Independent developer	70
	Independent power producer	28
	Utility	8
	Other	18
Investment phase ($n=105$, multiple choices possible)	Greenfield development	74
	Early maturity	67
	Late stage, financing	54
	Operations	55
	Construction	39
	Other	10
Respondent's experience with wind development ($n=105$)	<2 years	38
	3–5 years	23
	6–12 years	29
	>12 years	8
Company experience with wind development ($n=105$)	<2 years	20
	3–5 years	13
	6–12 years	26
	>12 years	33
Average project size ($n=95$)		
	<6 MW	9
	6–15 MW	24
	16–30 MW	31
	31–100 MW	28
	>100 MW	7
Cumulative investments over last 3 years ($n=73$)	<15 mio €	38
	16–100 mio €	18
	101–300 mio €	16
	301–1000 mio €	15
	>1000 mio €	12

multiple parts of the development, and are of small to medium size with annual development of up to 100 MW wind energy installation.

Table 4 shows the regional distribution. While many companies have their headquarters in Germany or the US, most are active in multiple European and US markets. Actual development activities are spread over the US and 25 countries throughout Europe.

4. Results and discussion

The root likelihood (RLH) indicates the goodness of fit of the HB model. In our model, it amounts to 0.751 indicating a good fit.

Table 4
Geographic distribution of development activities in our sample.

County	Development activities ($n=105$) count/(percentage) (multiple choices possible)	Headquarter ($n=105$) count/(percentage)
Northwest Europe	**162**	**60/(57)**
Germany	47/(45)	36/(34)
France	38/(36)	2/(2)
Great Britain	31/(30)	8/(8)
Sweden	19/(18)	2/(2)
Denmark	10/(10)	5/(5)
Austria	6/(6)	1/(1)
Finland	3/(3)	2/(2)
Other (Ireland, Netherlands, Belgium, Norway)	8/(8)	4/(4)
Southeast Europe	**194**	**23/(22)**
Poland	40/(38)	2/(2)
Italy	33/(31)	4/(4)
Romania	26/(25)	0/(0)
Spain	25/(24)	7/(7)
Bulgaria	25/(24)	2/(2)
Greece	14/(13)	1/(1)
Turkey	12/(11)	0/(0)
Croatia	7/(7)	0/(0)
Portugal	4/(4)	3/(3)
Slowenia	3/(3)	0/(0)
Other (Hungary, Serbia, Slovakia,)	5/(5)	4/(4)
US	**40/(38)**	**22/(21)**

Table 5
Holdout task: comparison of directly stated preference (SP) and model data.

	Option 1 (SP/model)	Option 2 (SP/model)	Option 3 (SP/model)
EU	76.71%/76.42%	21.92%/23.26%	0.01%/0.32%
US	70.00%/75.16%	30.00%/23.94%	0%/0.90%
Total	74.76%/75.74%	24.27%/23.87%	0.01%/0.39%

The RLH for each individual is the geometric mean of the probabilities of the different choices made by the individual. The probabilities are calculated using the posterior means of an individual's part-worth utilities in the MNL model (Wonder et al., 2008). The RLH of the model is the arithmetic average of all the individual RLH values (the upper level normal distribution is thus ignored). The RLH is between 1.0 (best possible value) and the probability of the different choices in the average task, i.e., our model with three choices has a minimum RLH of 0.33.

The analysis of the responses to the holdout task provides an indication of how well the utility values estimated from the ACBC model (indirectly stated preferences) were able to predict the respondent's actual holdout choices (directly stated preferences). The share of preference results are displayed in Table 5. The simulated share of preference values were within 6% of the actual preferences indicated in the holdout data.

4.1. Importance scores

Fig. 4 presents the means and standard deviations of the relative importance scores of the attributes examined in this study. "Legal security" (28.2%) and "Remuneration" (27.4%) have the highest importance scores, followed by "Administrative process duration" (17.1%). "Investment cash grants" (11.0%), "Grid access" (10.1%) and "Credit financing" (6.3%) are of lower importance.

Importance scores can be best interpreted as the degree to which the difference in utility between the best and the worst level of a given attribute impact the overall utility of the respondents. They are calculated based on attribute level part-worth utilities (see formula (4)), i.e., if the partial utility scores of a given attribute show a large discrepancy between the lowest and highest level, this attribute is important for determining the overall utility and thus its importance score is high. As a result, the importance scores are slightly influenced by the survey design (Wittink et al., 1992; Orme, 2010c), i.e., by the number and the range of attribute levels. More specifically, this means that if the levels of, e.g., the attribute "Administrative process duration" were designed to show extreme values—for instance, ranging from 3 months to 15 years—it would result in a slightly higher importance score than in the current study because such high discrepancies in development duration would make a big difference to developers. To include an adequate choice of attribute levels, they were selected with respect to the actual market conditions in the analyzed countries and verified by the expert interviews and own research on prevailing policy settings. Using real-world parameterization of the attribute levels ensures that the results are meaningful for both practitioners and policy-makers. As a result, some attributes show pronounced ranges in attribute levels (in particular, "Legal security" and "Remuneration"), reflecting the current differences of policy and regulatory situations.

The results indicate that factors representing sources of risks to the development process of wind energy projects such as legal security and the administrative process duration are very important to developers. As expected, "Remuneration" is an important attribute, but it is worth noting that it is not dominating. Many policy discussions tend to place a very strong focus on the level of FIT or credits, but this analysis suggests that the majority of total utility is derived from other aspects. Remuneration during the operating phase of the project is more important than upfront investment support measures (i.e., investment cash grants and credit financing). This does not mean that these measures do not have value for wind developers, but the lower importance scores of "Credit financing" and "Cash grants" reflect their lower impact on the internal rate of return (IRR) of a wind energy project. Using a simple discounted cash flow (DCF) model, we estimate that the impact of a one-level increase in "Remuneration" on the internal rate of return (IRR) of a wind energy project is three to four times higher than a one-level increase in "Cash grants" and almost ten times higher than for a one-level increase in the attribute "Credit financing". These considerations are well reflected in the importance score results, which indicate that respondents adopt rational behavior when stating their preferences.

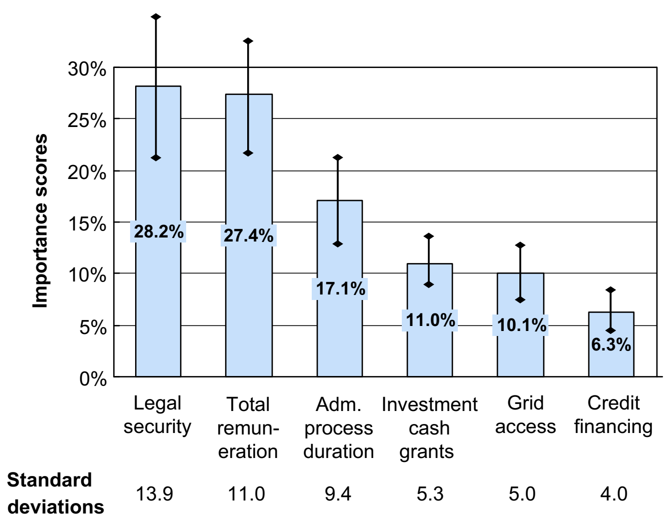


Fig. 4. Importance scores and standard deviations.

4.2. Unacceptable and most preferred attribute levels

In the screening section, 55% of the respondents indicated that they would not develop a wind energy project in a country where legal security is "Not given, corruption possible" (Fig. 5). For 31% of the respondents, the total remuneration needs to be higher than "5 € ct (7 $ ct)/kW h" and 26% see a "7 years" administrative process duration as a knock-out criterion. This shows that many project developers have critical minimum requirements and that they use, in the case of very high risks (e.g., very low "Legal security") or low remuneration, non-compensatory decision-making rules when evaluating opportunities.

Fig. 6 shows how often certain attribute levels have been included in the winning scenario of the choice task section. The most frequent attribute level is "1 year" administrative process duration (55%), followed by "Guaranteed, priority dispatch" grid regulations (48%) and the most favorable levels for "Legal security" and "Remuneration" (47% and 45%, respectively). For all attributes, the preferences consistently decline from the most favorable to the least favorable level. The frequency of the attribute levels of "Financing support" and "Cash grants" cannot be analyzed because their appearance frequency was influenced by the included prohibitions.

It is noteworthy that the two most preferred attribute levels in the winning scenarios ("1 year" and "Guaranteed; priority dispatch") are not from the attributes with the highest importance scores ("Legal security" and "Remuneration"). While the importance scores discussed above indicate the attributes for which developers show the largest preference differences between the worst and best levels, the winning scenario analysis provides insights into which aspects are most important to developers when they are looking for the ideal set of policy conditions in an investment environment. The results thus underline the high

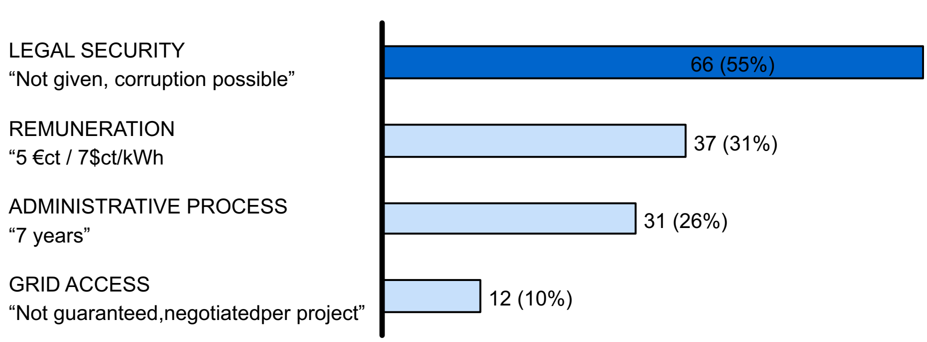


Fig. 5. Number of respondents that consider given attribute levels "unacceptable" for project development.

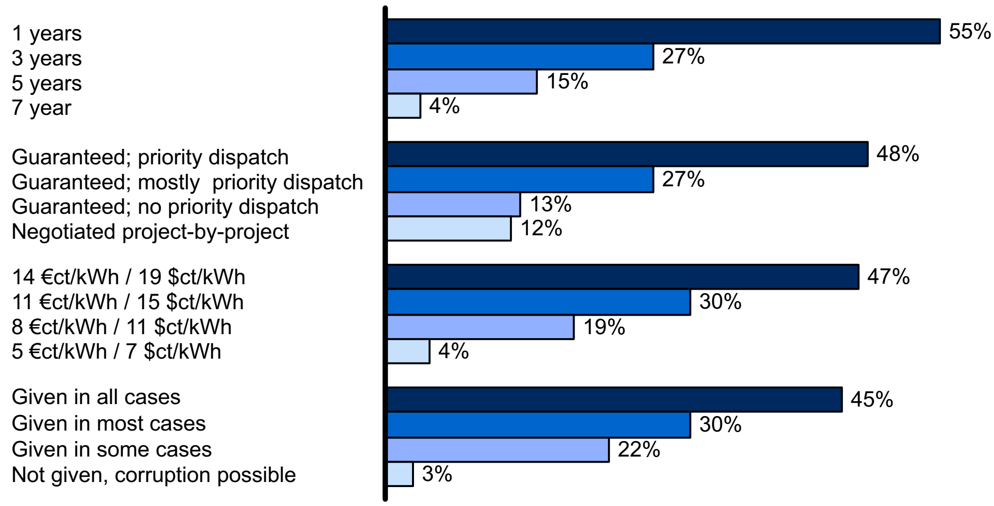


Fig. 6. Share of attribute level appearance in winning scenarios.

Table 6
Part-worth utilities (zero-centered diffs) and standard deviations for all attributes and levels.

Attribute	Attribute levels	Average part-utility	Standard deviation
Administrative process duration	7 years	−59.2	33.8
	5 years	−8.1	14.3
	3 years	28.1	16.7
	1 year	39.1	27.7
Legal security	Not given; corruption possible	−110.7	56.4
	Given in some cases	15.6	18.3
	Given in most cases	39.0	22.1
	Given in all cases	56.1	31.5
Grid access	Negotiated project-by-project	−27.5	23.3
	No priority dispatch	−7.0	16.9
	Mostly priority dispatch	14.8	12.4
	Priority dispatch	19.8	19.2
Total remuneration	5 € ct/kW h/7 $ ct/kW h	−93.4	42.7
	8 € ct/kW h/11 $ ct/kW h	−8.0	19.2
	11 € ct/kW h/15 $ ct/kW h	34.1	21.6
	14 € ct/kW h/19 $/kW h	67.3	33.2
Credit financing	No support	−15.0	18.7
	Gov. guaranteed soft loans 0.5% below market rate	4.2	14.1
	Gov. guaranteed soft loans 1% below market rate	2.9	12.6
	Gov. guaranteed soft loans 1.5% below market rate	7.9	14.4
Investment cash grants	0%	−31.9	23.3
	10%	−7.1	11.6
	20%	12.3	17.4
	30%	26.7	16.6

importance of short administrative processes during the development phase and grid access regulations that strictly favor renewable energy.

4.3. Part-worth utility estimation

Table 6 shows the average zero-centered diff part-worth utilities and standard deviations for all attributes levels.

Due to the considerations mentioned in Section 2.4, we compared the utility differences between the different levels of each attribute (cf. Fig. 7). In general, the amelioration of the worst situation delivered the highest utility gain. This is especially true for improving "Legal security" from "Not given; corruption possible" to "Given in some cases" (+126 utility points) and "Remuneration" level from "5 € ct/kW h/7 $ ct/kW h" to "8 € ct/kW h/11 $ ct/kW h" (+85 utility points). This finding corresponds well with the "unacceptables" identified above and explains the high importance scores of "Legal security" and "Remuneration." The low utility of the worst levels of these attributes (from people marking it as unacceptable) gives the importance scores a boost.

Any further improvement to the second and third best level of each attribute yields diminishing utility increases. There are only two notable exceptions. First, in the case of the attribute "Remuneration", respondents value the two subsequent increases of 3 € ct/kW h/4 $ ct/kW h revenue with similar utility gains. This makes sense as the impact on project profitability is equal. Second, in the case of "Grid access", the improvement from level 2 ("No priority dispatch") to level 3 ("Mostly priority dispatch") yields the highest utility gain within this attribute indicating the importance of priority dispatch for project developers.

4.4. Preference differences between various respondent groups

Within the literature concerned with deployment of wind energy some authors worked out that companies developing and investing in wind energy projects cannot be regarded as homogenous group. There is a multi-faceted variety of actors that drive wind energy development and they differ in aspects such as their motivation, risk aversion and profitability expectations (Enzensberger et al., 2002; Langniss, 1996). Various cluster analyses were conducted to further verify findings of these studies and also add new dimensions of differentiation of developers. Preference results were analyzed for differences with respect to type, size, and value chain focus of the developer companies, share of debt financing, the respondents' level of experience with wind energy development, and regional focus of development activities.

However, we find that preferences appear to be quite homogeneous across various subsets of the total sample. The fact that there are little discrepancies in policy preferences between different groups of developers may be a finding in itself. The following cluster analyses reveal small and thus statistically insignificant differences among subgroups. The findings regarding the following aspects are therefore indicative only:

Company size: Dinica (2006) has discussed how small and large developers will show different investment patters in different investment contexts, partly because they differ in their financing capabilities and equity requirements. The empirical study results now show that respondents from large companies show an above average preference for "Credit financing support"

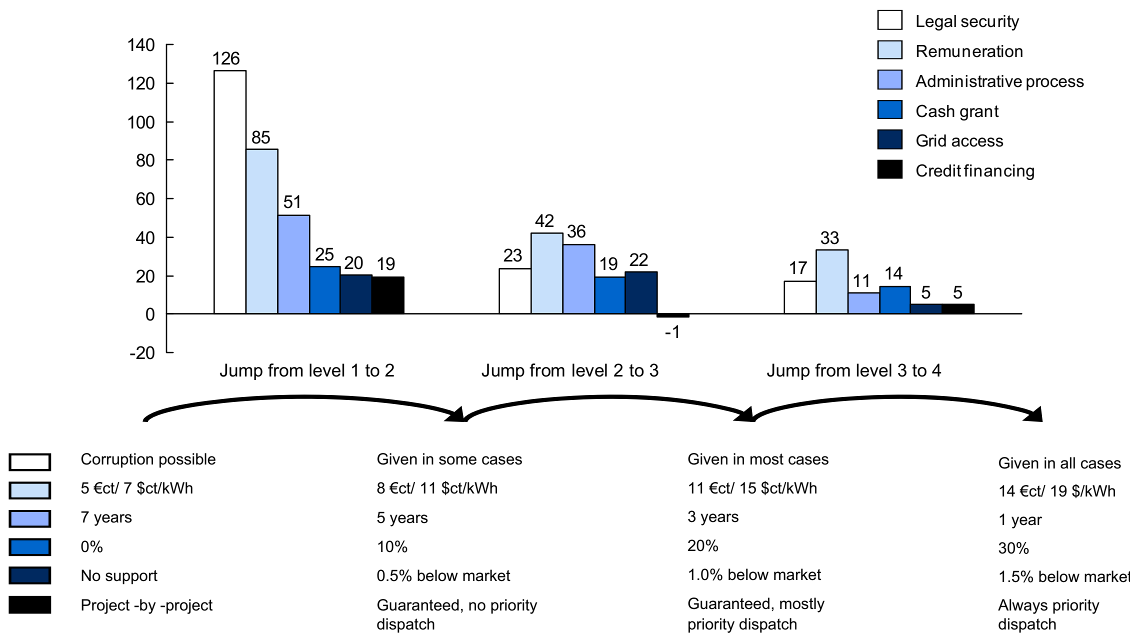


Fig. 7. Part-worth utility gains (zero-centered diffs) for improvement to the next higher level within a specific attribute.

(small companies vice versa)[7] compared to small companies. It seems plausible that financing becomes a more constraining factor with higher total capacity and capital volumes. The more projects a developer company keeps in its portfolio the more difficult it gets to provide sizable equity portions to the project finance and hence the more reluctant banks will be to provide debt finance. Financing guarantees or refinancing models with below market rate conditions[8] are helpful to overcome this constraint.

Value chain focus: Developer companies that integrate across the entire development value chain show some preference particularities. Compared to those that engage only in early development stages (greenfield and early maturity) they have a noticeably lower preference for "Legal security",[9] and place higher importance on "Grid access" and "Credit financing" support. These differences in preferences seem to reflect the respective issues that companies face: companies covering the entire value chain might be less susceptible to corruption risk in early siting and administrative procedures and at the same time are more concerned with securing financing and getting the wind park connected to the grid.

Project size: Developers of small projects (<10 MW) place substantially lower importance on "Remuneration" and higher importance on "Legal security" than developers of large projects (>50 MW).[10] This could be due to the fact that costs incurred by legal services and legal disputes and are proportionally higher for small projects than they are for large projects. As a result, developers might be willing to accept lower remuneration levels in exchange for a more reliable legal environment.

Experience: Respondents who have little experience in wind energy development (<2 years) deem the duration of the administrative process less important than very experienced developers (>8 years of experience).[11] The latter possibly have experienced the risks and challenges that come with lengthy administrative procedures whereas the former might not yet have developed a project to completion.

Yet other analyses that were conducted do not deliver statistically significant results because the respective groups sizes are too small. As for the type of developer company, studies suggest that different types of developer companies have different financing capabilities, costs of equity and risk appetites (Wiser, 1997; Enzensberger et al., 2002). Unfortunately, the study data cannot back their categorizations with new empirical findings because the respondent sample contains an insufficient number of utilities and independent power producers.[12] Therefore, the results cannot be reasonably interpreted. Similarly, less than ten respondents focus on late stage development only (financing and/or construction); too few for a reliable analysis.

The results of the regional cluster analyses are more conclusive and will thus be covered in more detail. To test for preference differences with respect to geographic focus of development activities, we clustered the respondents into three regional groups (US, NW- and SE-Europe). Table 7 presents an indicative assessment of the relevant criteria based on the expert interviews. While the conditions for wind energy projects are mainly specific to national policy regimes in Europe and state policy regimes in the US, the defined regions share some characteristics.

We found the wind energy development market to be quite international; German and Danish development companies have expanded their business into other European countries, many with a focus on Eastern and Southeastern Europe. A precise one to one allocation of respondents to regional groups is difficult as the majority of developers are active in two or three regions (only 45 out of the 108 respondents who indicated their activity countries confine their development activities to only one of the specified regions). As an approximation, we based regional clustering of

[7] Spread of Importance Score (IS) between the two groups: 2.2 points (full sample: IS 6.3).

[8] As offered by some development banks, e.g., the "Erneuerbare Energien Programm" of the German KfW Bank.

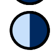
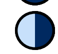
[9] Spread of Importance Score (IS): Legal security: 6.1 points (full sample: IS 28.0); grid access: 3.2 points (full sample: IS 10.0); and Credit financing: 1.6 points (full sample: IS 6.3).

[10] Spread of Importance Score (IS) between the two groups: Remuneration: 6.2 points (full sample: IS 27.5) and Legal security: 6.1 points (full sample: IS 28.0).

[11] Spread of Importance Score (IS): Adm. process duration: 4.4 points (full sample: IS 17.2).

[12] Less than ten per group.

Table 7
Characteristics of wind markets in different regions (two moons indicate variations within the region)

Criteria	US	Northwest Europe	Southeast Europe
	Countries		
	US	Germany, Netherlands, Belgium, UK, Ireland, Sweden, Denmark, Austria, France, Norway, Finland	Bulgaria, Croatia, Greece, Italy, Poland, Romania, Slowenia, Spain, Turkey, Bulgaria, Portugal, Czech Republic, Slovakia, Serbia
Maturity of wind market			
Legal security			
Grid capacity for wind power			
Administrative effectiveness			
Share of debt financing for wind energy projects			

=very low
=very high

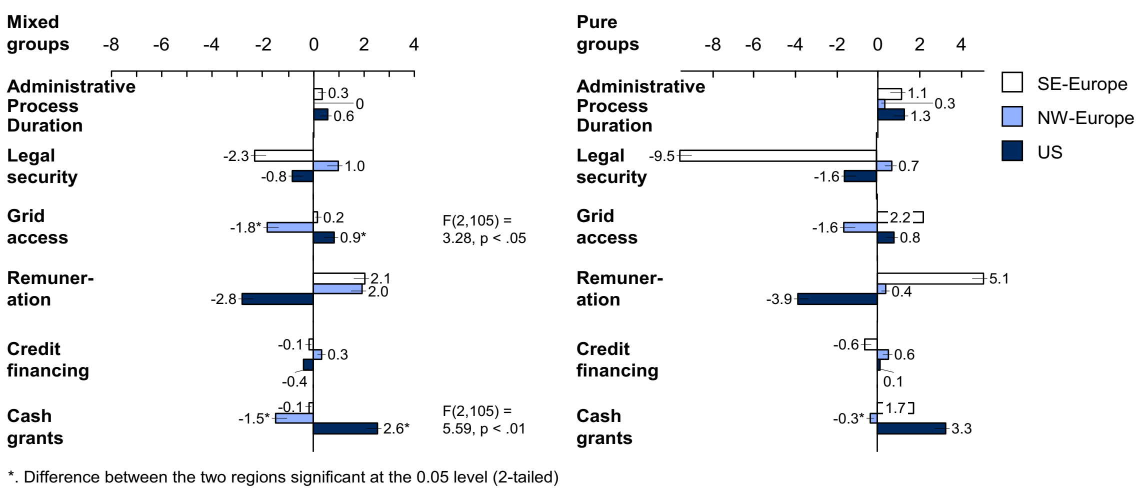


Fig. 8. Regional differences in importance scores—left hand side: mixed groups; right hand side: pure groups.

respondents on where the majority of their development activities take place (number of mentioned countries). This led to some overlap of preferences and diffused regional discrepancies to some extent. ANOVA was conducted to assess significant differences between groups. If the variable F from the ANOVA was significant, a Gabriel *post hoc* test was conducted to see which specific groups showed significant differences (Field, 2009). The p-values reported below are those derived through the Gabriel *post hoc* procedure. Differences that were not statistically significant are discussed as indicative trends.

Fig. 8 (left hand side) displays the regional differences of the importance scores. In general, the preference differences between the regional clusters were small. This makes sense, as, in theory, the impact of cash flows and risks resulting from the different attribute levels on project profitability and project quality should be in the same order of magnitude in different regions. However, the similarity was also due to the non-bijective regional allocation of respondents. Using only the 45 respondents ("pure groups") with activities in a single region, most discrepancies were more pronounced (cf. Fig. 8 (right hand side)). The "pure groups" results were indicative only, given the rather small sample sizes for such groups in each region (SE: $n=13$/NW: $n=13$/US: $n=19$).

We found three main differences in the preference structure of wind energy project developers from the three different regions.

The US developers seem to have a higher preference for short-term support ("Cash grant") and place less value on "Remuneration" during the operational phase of the wind project compared to the European developers. This could imply an implicit higher discount rate when evaluating development options. The analysis of the underlying part-worth utilities (cf. Annex) indicates that the US developers derive significant higher utility from cash grants above 20% and see the absence of a cash grant support as much worse than the NW-European developers. On the other hand, the US developers have lower importance scores for "Remuneration", mainly driven by the fact that they are more willing to accept the lowest remuneration level of 7 $ ct/kW h. The analysis of the "pure groups" indicates that this difference in preference is most pronounced between the US and SE-European developers. The latter place higher value on remuneration to compensate for comparatively higher development risks, such as the possibility of corruption.

The SE-European developers have a lower importance score for "Legal security" than both the NW-European and the US developers. The part-worth utility comparison shows that this is

Table 8
Illustrative policy scenarios representative of the regions NW-Europe, SE-Europe, and US.

Attributes	NW-Europe	SE-Europe	US
Administrative process duration	3 years	7 years	2 years
Legal security	Given in all cases	Given in some cases	Given in all cases
Grid access	Access guaranteed priority dispatch (no output curtailment)	Access guaranteedno priority dispatch (output curtailment is likely)	Negotiated on project-by-project basis
Total remuneration	8 € ct/kW h	11 € ct/kW h	5 € ct/kW h
Credit financing	Gov. guaranteed soft loans 1% below market rate	No support	No support
Investment cash grants	0%	10%	30%
Relative preference	83.33	31.02	38.36

mainly because the SE-European developers tend not to see corruption as a knock-out criterion, contrary to the other two developer groups (cf. Annex). This difference is even more pronounced in the "pure groups"; with a large difference between the SE- and NW-European developers.

"Grid access" seems to be a less severe bottleneck for the NW-European developers than for the US and SE-European wind energy developers. Their importance score is significantly lower because, on the one hand, they have less negative part-worth utilities for project-by-project negotiations and grid regulations without priority dispatch for wind, and on the other hand, value priority dispatch significantly less than other developers (cf. Annex). The developers from the US, for instance, show a much higher preference (+15 utility points) for a priority dispatch provision. The explanation for these differences could be that, in the US, most jurisdictions do not provide for guaranteed priority dispatch of wind energy. This poses a significant risk to wind energy plant owners as frequency of wind energy curtailments increases (e.g., in Texas in 2009, 17% of all potential wind energy generation was curtailed because of transmission inadequacy (Wiser and Bolinger, 2010)).

The observed differences in preference structures may (1) result from familiarity of the respondents with specific policy instruments, as in the case of higher preference for cash grants of the US developers; (2) reflect region-specific barriers to wind energy project development, as in the case of the preference regarding grid access; or (3) reflect cultural factors, such as the prevalence of corruption, which leads SE-European developers to accept lower legal security or the preference of US developers for a higher discount rate, which is shown by their higher preference for upfront cash grants and lower preference for remuneration. The importance scores for "Administrative process duration" are quite similar for developers from all three regions, in both mixed and pure groups.

4.5. Region-specific policy analysis

Preference simulations based on the conjoint analysis experiment data allow the gauging of the investment intent of wind energy project developers under specific policy conditions. Using formula (5), they provide a means of simulating the preference for a given policy environment as if in a stand-alone context, without having to contrast it to a set of alternatives:

$$p = (e^u/1 + e^u)$$

The simulations allow testing the extent to which the relative preferences p change when the levels of an attribute change, while keeping all other attribute levels constant. For each policy environment, changes in policy measures will have a different impact on the country's attractiveness for project developers. The preference simulations are not to be interpreted literally but are meant to serve as a gage or "barometer" for investment intent. We have constructed three illustrative scenarios of attribute level settings that roughly reflect northwest(NW)-Europe (scenario 1), southeast(SE)-Europe (scenario 2),[13] and the US (scenario 3) (cf. Table 8). Note that the scenario simulations shown here are based on the preference data of the entire sample to make them more robust and allow for a variety of scenarios.

4.6. Scenario NW-Europe

The hypothetical NW-Europe scenario (Fig. 9) has a high relative preference of 83%, mainly due to low policy risks (highest levels of "Legal security" and "Grid access"). Significant increase in perceived market attractiveness can only be reached by additional financial support. A "Remuneration" increase of 3–11 € ct/kW h or the introduction of a 10% "Cash grant" would yield the highest gain for developers (+11% and +9%, respectively). As the current market attractiveness is quite high, further policy changes need to be evaluated carefully to avoid over-subsidization. On the flip side, a reduction of the "Remuneration" would be very detrimental to the relative preference (−48%) and have serious implications for wind energy development activities in this market.

4.7. Scenario SE-Europe

The hypothetical scenario for SE-Europe (Fig. 10) has a relative preference of 31%. The attractiveness of this policy framework can be strongly increased by shortening the "Administrative process duration". A shorter process would increase the preference share to 62% (5 years) or to 82% (3 years). Substantial improvements could also be achieved by improving "Legal security", "Remuneration," or "Grid access".

4.8. Scenario US

The hypothetical US scenario (Fig. 11) has a relative preference of 38%. Its attractiveness would benefit most from increasing the "Remuneration" (+46% for an increase from 5 to 8 € ct/kW h). The reason is that the four levels within this attribute (5/8/11/14 € ct) have unevenly distributed part-worth utility values—the jump from 5 to 8 € ct delivers by far the highest gain (see Fig. 7). This is the case in any scenario with a low remuneration level. While this effect dominates, it does not contradict the finding from the importance score analysis above, which showed that US developers do not value the attribute "Remuneration" in comparison to other attributes quite as much as developers from other regions. If we take into account only preference data of

[13] As corruption is possible in many SE-European countries, we decided not to include this level in our simulation, as it has been shown (Section 4.2) that corruption is a knock-out criterion for many developers and should thus be addressed first.

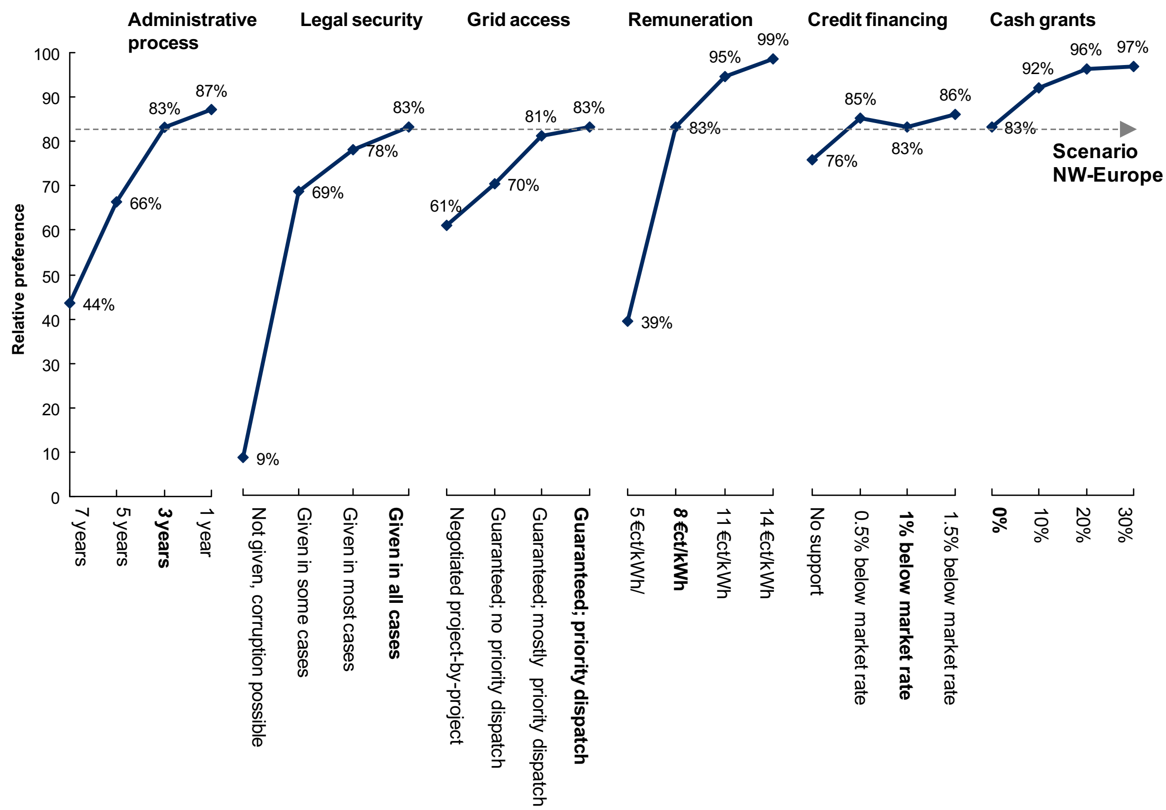


Fig. 9. Relative preference simulations for the NW-Europe scenario.

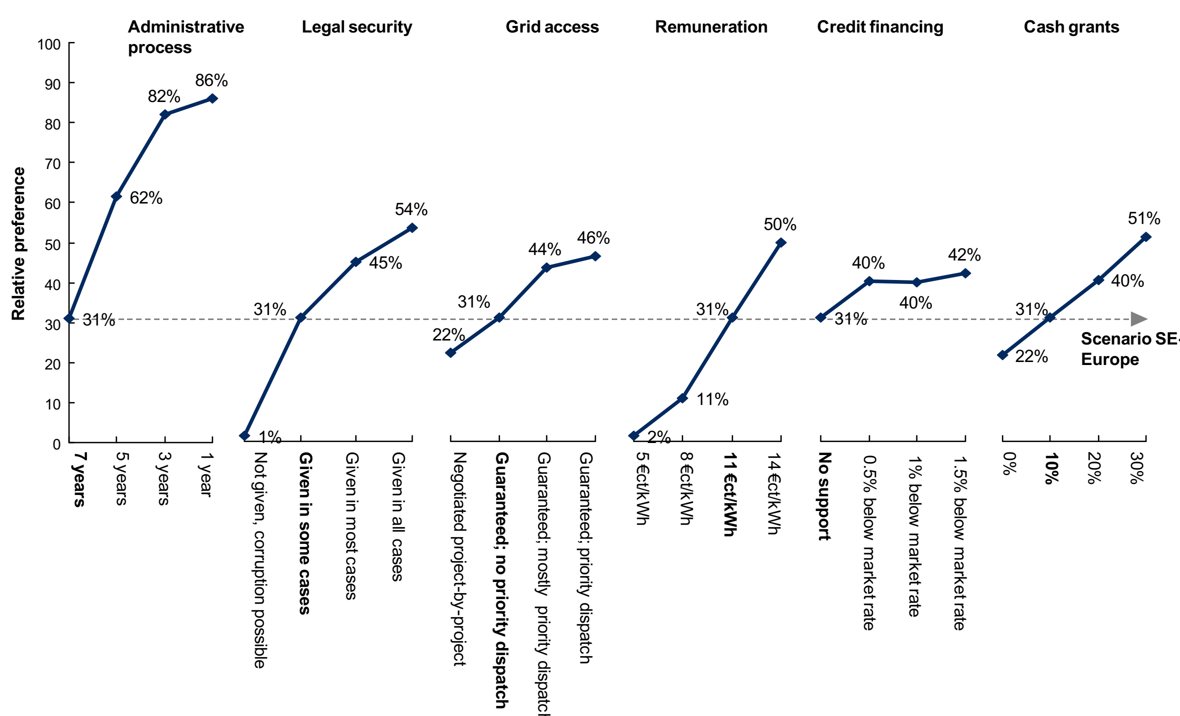


Fig. 10. Relative preference simulations for the SE-European scenario.

SE-European developers, the effect would be more pronounced than in the case of US developers data.

Improving "Grid access" so that priority dispatch is mostly given yields an increase of +24% in the relative preference. An increase in the relative preference of the scenario could also be reached by "Credit financing" opportunities. The introduction of government guaranteed soft loans 1% below market rate would increase the attractiveness of the base case scenario by 10%.

The importance score analysis in Section 4.4 showed for which aspects and by how much the preferences of developers from

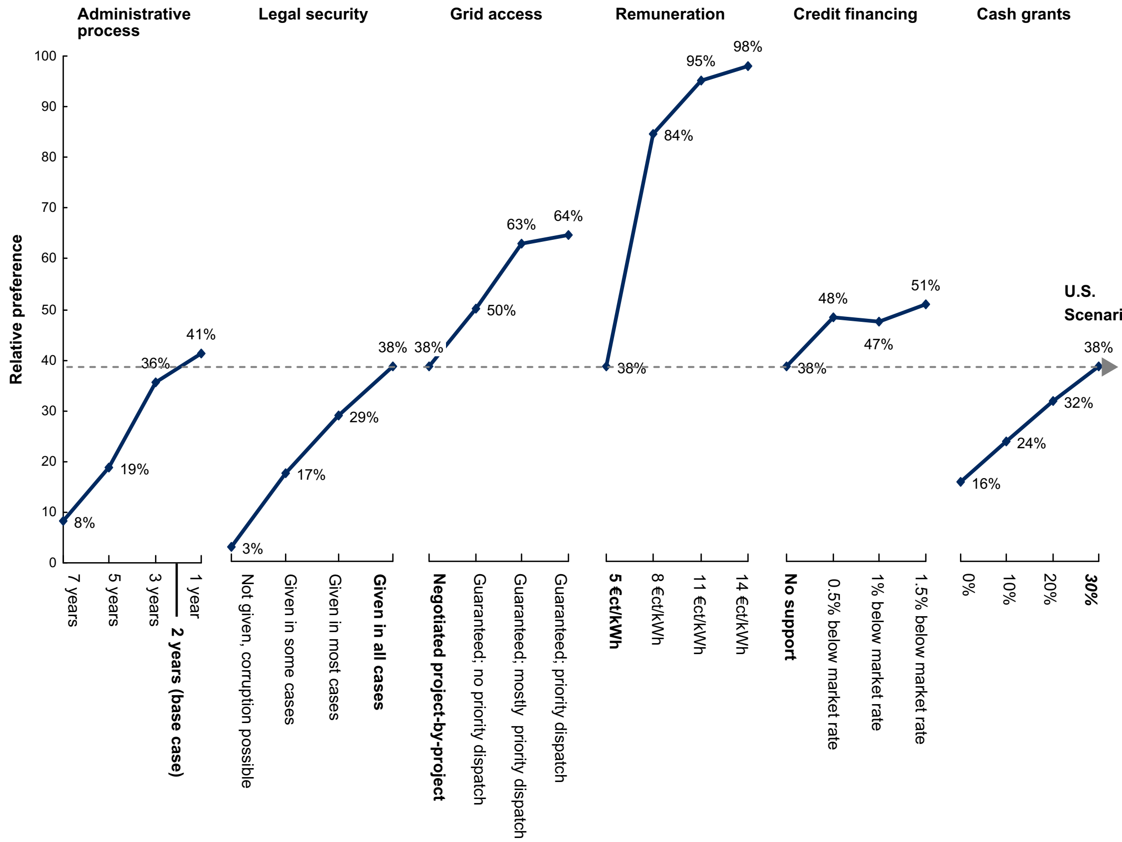


Fig. 11. Relative of preference simulations for the US scenario.

different regions differ. This can be important for policy-makers, for example, when adopting best practice policies from other regions. While the described regions share some common characteristics, policy-makers usually act on a national level. The results from the scenario analysis in Section 4.5 give guidance on which policy improvements could provide the highest utility gains for developers given a specific (national) context.[14] This section showed that the respective starting point is crucial to understand in which areas policy improvements have the biggest impact on developers' utility.

5. Conclusion

5.1. Summary and implications for policy-makers and project developers

The objective of this paper was to examine project developers' policy preferences to enhance the deployment of wind energy. This study builds on the findings of existing literature and substantiates them by employing a novel research methodology, providing an empirical dataset of wind developers' preferences and making the impact of various policy factors on developers' utility measureable. It also suggests that conjoint analysis could be a helpful tool for the estimation of potential effects of specific policy measures.

Key findings can be summarized as follows:

First, wind energy project developers value risk mitigation highly. Legal security, short administrative process duration, and favorable grid access regulations are very important to developers. These findings are in line with the conclusions of previous studies (Langniss, 1996; Wiser and Pickle, 1998; Dinica, 2006 among others) and confirm their results with empirical preference data. "Legal security" and "Remuneration" have the highest importance scores, whereas, when selecting the most preferred policy scenario, developers indicated the highest preference for very short "Administrative process duration" and "Grid access" regulation that guarantees priority dispatch.

Second, developers have critical minimum requirements for development and as a result they use non-compensatory decision-making in the case of very unfavorable attributes. More than 50% of the wind energy developers see the possibility of corruption, and about 30% see the lowest remuneration level included in the study (5 € ct/kW h respective 7 $ ct/kW h) and an administrative process duration of 7 years, as knock-out criteria. The study also shows that in most cases, the amelioration of the worst situation brings the highest utility gain.

Third, the preferences of the surveyed developers are quite similar across different types, sizes, value chain foci of the developer companies, and the respondents' level of experience with wind energy development. Indicative findings suggest that developers of small projects and less integrated companies show stronger preferences for "Legal security", whereas large and more integrated companies show above average preferences for "Credit financing support" measures. With respect to the three different regions US, SE-Europe and NW-Europe preferences are also quite similar in general, but show some differences resulting from different regional wind energy barriers, familiarity with different policy instruments, and cultural factors. First, the US developers show a higher

[14] While the presented scenarios are illustrative for regions, the data could be used to conduct similar analyses on a national level.

preference for upfront investment cash grants and a lower preference for production-based remuneration than the European developers. This difference could be caused by an implicitly higher discount rate of the US developers or policy schemes familiarity (i.e., US developers are more familiar with cash grants, while European developers are more familiar with a feed-in tariff support scheme). Second, in SE-Europe where corruption is comparatively more common, this issue tends to be seen as less problematic. In return, the remuneration expectations are higher. Third, the US and SE-European developers state a higher preference for grid access regulations that secure priority dispatch for wind energy than NW-European developers. The latter usually have the benefit of such provisions and the former experience the lack thereof and thus have higher awareness for the need.
Fourth, the most valuable policy measures for developers differ depending on the specific policy framework in place. The preference simulations indicate that in a scenario emulating SE-Europe, streamlining of the administrative processes and increasing legal security are of the highest value to increase market attractiveness. In the US scenario, improvements in grid access regulation and higher remuneration would render the development of wind energy plants more attractive. In the NW-Europe scenario, market attractiveness is already very high and could only be significantly enhanced further by higher financial support.

These results have important implications for policy design:

- When designing support policies for wind energy promotion, policy-makers should focus on risk minimization measures, especially regarding legal security, administrative process duration and grid access issues (compare Bürer and Wüstenhagen, 2009; Lüthi, 2010).
- Policy-makers should first address knock-out criteria such as corruption and very low remuneration to avoid obstacles to the deployment of wind energy.
- When designing support policies, policy-makers should take into account that the most effective support measures are strongly dependent on the current policy environment. The illustrative regional analyses can help policy-makers to identify the policy measures that result in the biggest utility impact in the developer community and to gage the relative importance of these changes in terms of preference increase for project developers.
- Finally, the result that the preferences of the surveyed developers from the three different regions are generally quite similar indicates that the results of this study are transferable to individual countries or other regions with comparable investment environments. However, when designing or changing wind energy policies, policy-makers should take into account support policy familiarity of the project developers active in their region, cultural factors like investment discount rate and, as mentioned above, especially address problems that are of primary concern for the development of wind energy projects in their region.

The results of this study are also relevant to wind energy project developers and allow them to learn more about their own decision-making and gain insights that help them benchmark their decision-making process with industry peers.

5.2. Limitations and further research

This study suggests that conjoint analysis can serve as a useful scenario tool for assessing the effect of policy measures on developer utility, but there are several limitations regarding its use, which should be taken into account in further studies. First, the insights are based on stated preferences and not on revealed actual behavior. What developers say about their decision-making process might be different from how they decide in reality. Real life complexity cannot be mirrored 100% with a limited number of attributes. This tends to lead to overestimation of the studied aspects (Orme, 2010a).

Second, preference simulations based on conjoint analysis data do not provide the functionality of a market model. Typical market based factors influencing the development decision (cf. Table 1) such as competition, demand, capital availability, or alternative investment options in other forms of energy generation are not considered. Hence, our results inform about preferences of developers for certain policy measures and how small changes to these policies might improve the perceived attractiveness of policy schemes. However, these results taken on their own cannot predict market reactions to changes in policy schemes.

Third, the study employs the same approach and survey across different national wind energy markets. While the assessed attributes are important decision-making drivers in all national policy schemes, most of the "Organizational and behavioral factors" (cf. Table 1) that were beyond the scope of the study are distinctive to national investment cultures and can have a great bearing on the conduct and decision making of developers. Studies found that relevant national and local institutional factors include spatial planning institutions, landscape protection concerns, (Nadaï, 2007; Toke et al., 2008; Prados, 2010), ownership structures (Delmas and Montes-Sancho, 2011; Agterbosch et al., 2004; Toke et al., 2008; Munday et al., 2011), and peculiarities in national business cultures (Dinica, 2008). A good example of the latter is the crucial role that government participation played via public–private partnerships (PPPs) for expediting wind energy development in Spain up to the mid-1990s. Despite reasonable risk/return conditions, investors had only been willing to invest in wind energy when public authorities took on part of the risks and equity shares via PPPs. Even with the advance of fully private investments, 'partnering' persisted as a successful development practice and became enrooted in the Spanish wind energy industry (Dinica, 2008). In sum, these factors are crucial for the development decision making, and developers will thus evaluate a preference survey against their specific national backgrounds and development experiences.

Furthermore, the large scale quantitative design of the study limits its insights into individual attributes of the respondents of which we could only cover the experience level. Other relevant attributes include for instance the respondents' level of risk aversion, confidence in policy development or project management capabilities. To capture these less tangible aspects, further research could deliver more granular insights by employing qualitative in-depth case studies on wind energy development projects.

Finally, as discussed in Section 4.4., differences in preference structure of different types of developers could not unequivocally be assessed due to the low representation of some groups in the respondent sample. Larger and more balanced samples, including more utility developers and more developers engaging in late stage financing could deliver more solid insights into their specific preference structures.

Our findings could be extended by further research in other regions, such as developing countries. Such a study would need to consider including other region-specific attributes such as overall political stability, investment costs and currency risk. Similarly, a study focusing on other renewable energy technologies would yield interesting results for comparison, but is likely to require other attributes to accommodate different economics and diffusion barriers. Further research could explore possibilities of linking

Table A1
Zero-centered diffs art-worth utilities and standard deviations (SD) for all attributes and levels for the total regional three regional groups (SE-Europe, NW-Europe, and US).

Attribute	Attribute levels	Total utility (SD)	SE-Europe utility (SD)	NE-Europe utility (SD)	US utility (SD)
Administrative process duration	7 year	−60.4 (33.3)	−60.8 (32.5)	−59.9 (32.5)	−60.5 (35.7)
	5 years	−8.3 (14.7)	−6.9 (15.2)	−8.1 (13.9)	−10.2(15.2)
	3 years	28.8 (16.6)	27.9 (17.7)	28.2 (15.2)	30.4 (17.3)
	1 years	39.9 (27.8)	39.7 (23.9)	39.8 (27.4)	40.3 (32.6)
Legal security					
	Not given; corruption possible	−107.4 (54.3)	−98.8 (59.0)	−113.2 (48.8)	−110.3 (55.1)
	Given in some cases	15.3 (18.0)	10.8 (15.6)	14.3 (17.1)	21.4 (20.1)
	Given in most cases	37.8 (21.2)	34.7 (24.0)	38.9 (19.4)	40.1 (19.9)
	Given in all cases	54.2 (29.2)	53.3 (34.6)	59.9 (26.6)	48.8 (24.9)
Grid access					
	Negotiated project-by-project	−25.5 (22.5)	−29.9 (19.4)	−19.4 (22.1)	−27.5 (25.1)
	No priority dispatch	−7.5 (17.2)	−6.4 (16.7)	−2.6 (15.1)	−13.9 (18.4)
	Mostly priority dispatch	14.3 (12.2)	14.5 (14.2)	12.7 (11.2)	15.7 (11.1)
	Priority dispatch	18.7 (18.9)	21.8 (17.8)	9.4 (18.2)	25.6 (17.3)
Total remuneration	5 € ct/kW h/ 7 $ ct/kW h	−95.9 (42.0)	−100.8 (48.2)	−104.6 (32.1)	−81.0 (41.5)
	8 € ct/kW h/ 11 $ ct/kW h	−7.5 (19.4)	−5.3 (18.3)	−5.4 (22.7)	−12.3 (16.2)
	11 € ct/kW h/ 15 $ ct/kW h	34.6 (22.0)	34.9 (22.4)	39.2 (20.8)	29.3 (22.3)
	14 € ct/kW h/ 19 $/kW h	68.8 (33.0)	71.2 (38.5)	70.8 (28.8)	64.0 (31.0)
Credit financing					
	No support	−14.1 (18.9)	−15.7 (17.6)	−13.7 (23.4)	−12.8 (14.9)
	Gov. loans 0.5% below market rate	4.4 (14.4)	6.4 (12.5)	6.5 (16.0)	−.1 (13.8)
	Gov. loans 1% below market rate	2.1 (12.4)	.7 (11.4)	.6 (13.7)	5.3 (11.6)
	Gov. loans 1.5% below market rate	7.6 (14.8)	8.6 (14.5)	6.6 (16.8)	7.6 (13.0)
Investment cash grants	0%	−32.8 (24.0)	−32.0 (20.2)	−24.1 (22.9)	−43.2 (25.7)
	10%	−7.0 (11.6)	−6.4 (13.6)	−6.3 (10.1)	−8.4 (10.9)
	20%	12.8 (17.8)	10.6 (15.1)	7.6 (17.4)	20.9 (18.6)
	30%	27.0 (17.1)	27.7 (18.3)	22.9 (16.6)	30.6 (15.8)

stated preference data with actual revealed data such as wind capacity installations. This would allow the calibration of choice data with market data. These techniques have mainly been used in the study of travel choices (Hensher et al., 2001). Another extension could be to include additional factors that potentially influence the project developers' choices such as competition levels, the influence of industry networks and the level of social acceptance of wind energy. Lastly, the activities of project developers are also steered by the preferences and investment strategies of their customers, including a variety of investor classes such as large utilities, financial institutions or welfare funds. Thus, an investigation about how developers' preferences are influenced by the preferences of final wind asset holders could provide a more holistic understanding of wind energy development dynamics.

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Annex

See Annex Table A1.

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Chapter 3

Developing Offshore Wind Power—Developers' Assessment of Key Barriers and Regulatory Influence in the UK and Germany

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Developing Offshore Wind Power: Developers' Assessment of Key Barriers and Regulatory Influence in the UK and Germany

Abstract

The study is based on in-depth expert interviews with representatives of 13 leading offshore wind power development companies that drive the majority of offshore wind park (OWP) projects in the UK and Germany. Goal of the study is to identify the main barriers to offshore wind power deployment and to scrutinize how regulatory influence can help to overcome them. The study covers a wide range of aspects including support levels, project profitability, grid access regulations, financing, administrative conduct, permitting procedures, and legal risks. The discussion points out how these aspects affect different generic types of developer companies and highlights the main differences between the UK and Germany.

Results indicate that (1) the risk-return profiles of OWPs are less attractive than those of more established renewable energy technologies (RETs); (2) overall the UK offshore market is considered to be more attractive than the German on multiple dimensions; (3) energy companies will not be able to finance the expansion of offshore wind power on their own; and (4) the 2020 government targets for offshore wind power deployment will likely not be reached.

Keywords: *Offshore wind, deployment barriers, renewable energy financing*

1 Introduction

To decarbonize existing energy systems, a shift toward zero carbon technologies is needed. With nuclear power facing strong opposition in many European countries and carbon capture and storage of fossil fuels struggling with technological and acceptance issues, a large share of future power generation capacity must come from RETs. Among the various RETs employed today, offshore wind power plays a pivotal role in delivering a substantial share of future renewable electricity generation in Europe[1]. EU nation states stipulate a total capacity of roughly 42 GW will be installed by the year 2020 (European Commission 2010). The most ambitious development goals exist in the UK and Germany, where 13 GW[2] and 10 GW of offshore wind power capacity, respectively, are planned by 2020 (European Commission, 2010c). Both countries employ support policies to foster this expansion (see Table 1).

Table 1
Offshore wind power capacities and policies in Germany and the UK

Country	Current Capacity (Q2 2011)	Planned Capacity (2020)	Deployment policy	Level of remuneration
Germany	195 MW	10,000 MW	Feed-in tariff (FIT)	Phase 1: 19 ct/kWh for 8 years; 15 ct/kWh for possible extension months Phase 2: 3.5 ct/kWh after phase 1 until year 20
UK	1,586 MW	13,000 MW	Tradable green certificates (TGCs)	Electricity market price plus 2 renewable obligation certificates (ROCs) per kWh

Sources: National Renewable Energy Action Plans (European Commission 2010); EWEA (2009; 2011a; 2011b)

The goal of this paper is to scrutinize current dynamics of offshore wind power deployment in Germany and the UK toward the 2020 expansion goals. Identifying the most important barriers and risks, the study aims to scrutinize how policy makers can design and implement energy policy instruments to best address these barriers. Focus will be on understanding which effect implementation choices for policy instruments have on how developers perceive the attractiveness of policy regimes.

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[1] According to a study by the EEA, the theoretical technical offshore wind power potential in European waters amounts to 3500 TWh in 2030. Theoretically, this could be enough electricity to supply approximately three-quarters of Europe's predicted electricity consumption in 2030 (EEA 2009).

[2] In the third quarter of 2011, the UK government increased this goal to 18 GW by 2020 dependent on advancements in significant cost reductions (Department of Energy and Climate Change 2011)

2 Literature context

Scientists have debated which support policies are most appropriate for deploying RETs (Rickerson et al. 2007; Cory et al. 2009). Empirical evidence from many countries suggests that FITs are the most efficient and most effective primary policy mechanism to spur rapid deployment of RETs (Ringel 2006; Stern 2007; Lipp 2007; Ragwitz et al. 2007; Fouquet & Johansson 2008; Dong 2011). Quantity-driven mechanisms seem to entail higher levels of financial risk for investors due to price volatility and offtake risks (Butler & Neuhoff 2008; Mitchell et al. 2006; Doherty & O'Malley 2011).

However, the devil seems to lie in the details. Scientists point to the importance of the specific design criteria and implementation choices of policies (Wiser & Pickle 1998; Menanteau et al. 2003; Ringel 2006; IPCC 2011; Haas et al. 2011). Recently, researchers have started to investigate the impact of complementary enabling instruments and regulations that govern the development procedures. These include instruments targeted at reducing financial and investment risks, facilitating planning and permitting procedures, regulating grid access, and enabling capacity and knowledge building (IPCC 2011). Iglesias et al. (2011) showed that intransparent permitting procedures and the lack of coordination between different administrative levels decrease investors confidence and increase transaction costs. Similarly, others have shown how the structure of permitting and planning procedures for offshore wind power installations in Sweden (Soderholm & Pettersson 2011), Germany, and the US (Portman et al. 2009) influence the speed and efficiency of deployment. Regulating grid access is another important framework condition for deploying renewable energy (Klessmann et al. 2011; Prässler & Schaechtele 2012). Alagappan et al. (2011) found that markets where policy makers conduct anticipatory transmission planning and where developers do not have to bear the costs of transmission interconnection are more successful in deploying RETs than those that do not.

To understand which enabling policy measures are needed in which context and how regulations governing the development processes of RETs can be tailored to eliminate bottlenecks it is helpful to adopt the perspective of developer companies and investors. They are the intermediaries operating at the nexus of the political and the financial arena, effectively linking government targets on RET expansion expressed in form of deployment policies with the capital funds needed to turn those targets into reality. When designing energy policies, policy makers should therefore consider how these policies affect developers and investors: "*Supporting the dissemination of RET means supporting people, not technologies. [Therefore], support mechanism have to be adapted to people, not to technologies.*" (Langniss 1996, p. 1112). Academics have adopted the investors' and developers' perspective to differentiate different types of investors according to their motivation, level of risk aversion, and financial capabilities (Langniss 1996; 1999); developed conceptual frameworks structuring investors' perceptions of risk and return (Dinica 2006); and provided empirical evidence on the investors' and developers' preferences for various types of policy mechanisms (Bürer & Wüstenhagen 2009). Despite these advances, the link between renewable energy policies and the decision-making processes of investors and developers needs to be explored further: *"The empirical evidence about how policies and their risk are actually perceived by investors and project developers has been limited so far"* (Wüstenhagen & Menichetti 2012).

This paper provides empirical evidence on offshore wind power deployment processes, analyzing the details of implementation choices and enabling policy measures by adopting the developers' perspective. The next section explains the employed research methodology, study design, and sample construction. The subsequent section then discusses the results.

3 Methodology

The presented study employs interview-guide-based expert interviews as data collection method and qualitative content analysis as interpretive methodology. The qualitative approach allows for more in-depth analyses of complex processes (Eisenhardt 1989; Mayring 2010) and accommodates the relatively small number of available experts in the offshore wind power markets. To enhance construct validity of the research approach (Denzin & Lincoln 2005; Yin 2003) findings from the expert interviews are triangulated with available scientific publications and industry reports, company information, and information gathered at conferences[3].

According to a classification of Gläser and Laudel (2009) the applied methodology is the nonstandardized expert interview with Interview Guide. The design of the Interview Guide adheres to the four principles (1) reach, (2) specificity, (3) depth, and (4) personal context

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[3] Conference organized by the "Bundesverband für Windenergie" (BWE): "Finanzierung Offshore Windenergie" (2011, Munich) and the EWEA Annual Event 2011 (2011, Brussels)

(Merton & Kendall 1979; Hopf 1978). The Interview Guide (see Appendix II) follows the above stated research objectives and leverages the attributes for wind power development identified by Lüthi and Prässler (2011) as structural guideline. To improve construct validity—referring to *"the quality of the conceptualization or operationalization of the relevant concept"* (Gibbert et al. 2008, p. 1466), the list of questions was revisited after the first five interviews for relevance and completeness.

Scope and sample

The study scope comprises the UK and Germany. These countries (1) represent the two largest future offshore wind power markets; (2) employ different deployment policies (green certificates versus FIT), and (3) differ in some crucial secondary regulations (e.g., grid connection regulations).

In total, 17 interview partners from 13 offshore wind power development companies participated in the study. The majority of interview partners have long-standing expertise[4] with > 90% of the interview partners being involved directly in developing offshore wind power projects. More than 50% carry management responsibility, being either the head of the Offshore Business Unit or the leading project manager for specific OWP development projects. All interview partners work for companies that are active in planning and developing OWPs; most of these companies also engage in constructing and operating OWPs. The sample includes six large, private energy utilities (including all four large energy utilities in Germany); five small- to medium-sized independent developers (IDs); three municipal utilities; and one special purpose vehicle.[5]

All companies are headquartered in Germany, Denmark, Spain or the UK. Combined, they are responsible for 13 of the 15 OWPs that are closest to completion in Germany and represent 76.4% market share of ownership of German OWPs under development[6] (Wind:research 2011). In the UK, the companies represented in the sample are active in developing 20 of the 28 Round 1 and Round 2 project areas (71.4%) (Scottish Enterprise 2010). The high coverage enhances external generalizability of the results (Maxwell 1992).

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[4] Average of five years experience in a very young industry. In Germany, the first test field, Alpha Ventus, was inaugurated in 2010.

[5] The vehicle company was established for the sole purpose of developing and constructing an OWP.

[6] This represents the percentage share of ownership of the OWPs that are operating, under construction, and consented OWP, as measured by capacity (effective May 2011).

Table 2 displays the composition of the interview sample. Overall, the sample is a diverse set of interviewees with a balanced representation of developer types, countries, and organizational functions.

Table 2
Composition of Interviewee Sample (17 interviewees from 13 companies)

			Company												
	Category	**Total**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**
Developer type	Private utility	6	X	X	X	X	X	X							
	Municipality	3							X	X	X				
	Independent developer	3										X	X	X	
	SPV	1													X
Country of offshore activity	Germany	13	X	X	X	X	X	X	X	X	X	X	X	X	X
	UK	5	X	X		X	X	X							
Function of Interviewee*	Commercial project manager	5					E1	F1	G1		I1		K1		
	Technical project manager	2										J1			M1
	Head of Offshore Department	4	A1			D1				H1			K2		
	Manager in Offshore Department	6	A2	B1	C1	D2								L1 L2	
	Sum of interviewees	17	2	1	1	2	1	1	1	1	1	1	2	2	1

* Note that in some cases, interviewees represent multiple classifications (e.g., "commercial project manager" and "head of Offshore Department". In this case, the hierarchally higher function is indicated.

<u>Interview process and content analysis</u>

All interviews were conducted either in person or via telephone between April and August 2011, lasting between 35 and 90 minutes. When interviewees consented, the interviews were recorded for better reconstruction. All sound files were transcribed into written interview protocols. To ensure reliability of the analysis, all documentation was collected into a central database as suggested by Gibbert et al. (2008). The interview protocols established the basis for the content analysis. According to Mayring (2010), content analysis analyzes (fixed) communication in a systematic way; is driven by rules and theory; and wants to abstract insights from certain aspects of communication. Three basic techniques of content analysis are common across different methods of interpreting content: synopsis, structuring, and explication. All three techniques have been applied in the present study.

The process of synopsis followed the sequence proposed by Meuser and Nagel (2009). First, sound files, protocols, and interview notes were transcribed. All interview transcriptions were then condensed[7] to capture the information that was relevant for answering the guiding questions. Then, the condensed interview summaries were coded, which involved dissolving interview sequences and sorting statements along the studied aspects. The resulting document constituted the basis of the content analysis, allowing for (1) differentiating opinions from different types of developer companies and (2) providing quantitative indication of whether the shared consensus on each studied aspect was diverse or homogenous.

4 Discussion of results

4.1 Barriers to offshore wind power development

To obtain an unbiased perspective from the interviewees, each interview started with an open question, asking for their perspective on the most significant regulatory barriers to developing offshore wind projects (see Interview Guide in Appendix II). Interviewees were asked to name up to five aspects; no categories were provided.

A wide range of topics emerged and answers were clustered content-wise into 12 categories. Figure 1 shows, on a simple counting scale, which aspects the interviewees mentioned spontaneously in response to the open question as the first 2 and first 5 aspects, respectively. Because interviewees tend to respond in decreasing order of importance, the number of mentions in the "Top 2" list may indicate a higher importance.

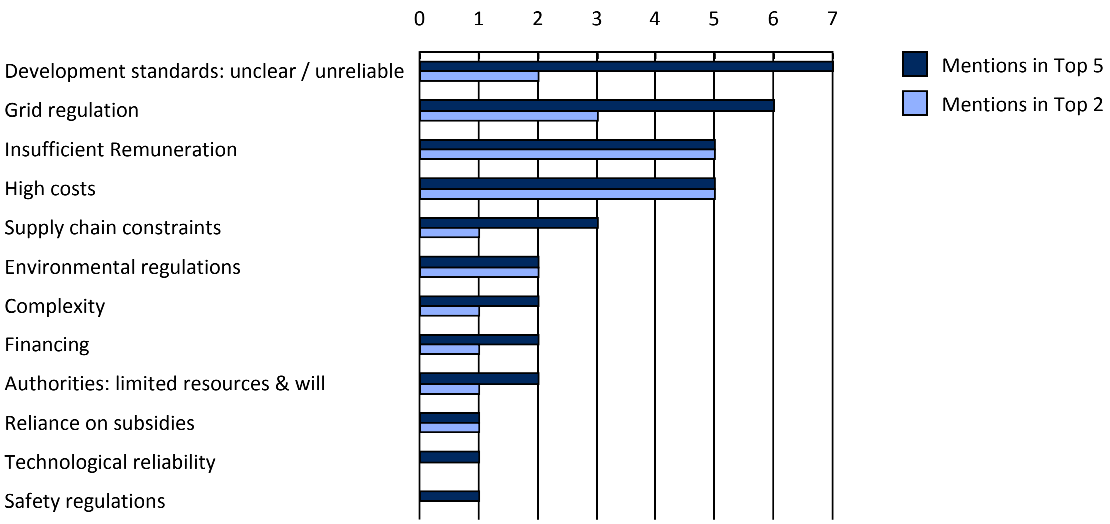

Figure 1: Mentions of main barriers to offshore wind power development in open question section
Note: Not all interviewees provided 5 items; similar answers were clustered into categories.

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[7] This step includes paraphrasing statements while preserving relevant information from the original interview protocols (including important quotes).

> Finding 1: The most salient barriers to offshore wind power development are: (1) unclear/unreliable development standards; (2) risks related to grid access regulations; (3) insufficient remuneration levels; and (4) high costs.

This list is based on the developers' perceptions only, reflecting the number of mentions in the "Top 5" answers. The four barrier categories are also top of the list when ordered by the "Top 2" mentions, albeit in reverse order. All issues will be explained in detail below.

4.2 Profitability

Project profitability it is a measure of how the net revenues and costs of a project relate to the invested capital (Lüthi & Prässler 2011, p. 4879).

> Finding 2: The level of expected profitability is one of the most important drivers for the development decision. At the same time, it is currently perceived as one of the main barriers for offshore wind power development.

While the first part of this finding is noncontroversial, the second part is more provocative: Developers perceive current profitability levels as inadequate. Many experts worry that insufficient profitability levels constitute a key economic barrier for the respective national development goals for offshore wind power. This is also reflected in Figure 1: high costs and insufficient remuneration levels were mentioned a total of 10 times as either a first or second response.

To understand why this perception of inadequate profitability levels prevails and whether it can be vindicated, two questions are of interest: (1) What are the main drivers of the profitability of offshore wind power projects? The below analysis of these drivers concludes in Findings 3 – 6; focusing on revenue support schemes and costs[8]. (2) What criteria can be applied to determine adequacy when it comes to the profitability of offshore wind power? Dinica (2006) argued that the notion of profitability needs to be put into context with the associated risks. Low expected project profitability in a low risk investment environment might be just as attractive as high expected project profitability in the context of high risks. Thus, it is not the absolute level of profitability that determines its adequacy, but the relative profitability-risk-ratio compared to alternative investment projects.

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[8] For a fact-based analysis of profitability prospects of offshore wind power plants please see Prässler and Schaechtele (2012)

This ties in with an argument advanced by most of the interviewed experts:

> Finding 3: Offshore wind power offers a less attractive ratio of risk and return than more established RETs such as onshore wind and solar PV.

Many experts noted that the risks of developing an OWP remain substantial. The technology is still error-prone, the development process is lengthy, risky, and often suffers from cost-overruns. At the same time, experts claim that these high risks levels are not matched by sufficiently high profitability levels. Without disclosing exact numbers for confidentiality reasons, various experts claimed that unlevered offshore wind projects in Germany yield less than 10 per cent return. In the UK, these numbers are slightly higher. As a benchmark for comparison, many interviewees quoted investments in other RETs. A solar PV plant, for example, has a low-risk profile, characterized by a proven technology, few operational risks, and a very short development horizon. The attainable profitability ranges between 7 to 8%. Given the high difference in risks, the attainable return levels of offshore wind power projects are *"Not enough to warrant further investments in offshore wind projects."* (C1).

When interpreting these results, three things should be noted. First, respondent biases might exist as interview partners represent companies that would benefit from improved remuneration levels. Second, no unanimous consensus exists among developers that profitability levels are indeed inadequate. Five experts, four of which work for IDs or municipalities, deemed the current profitability levels of OWPs in Germany acceptable. This may imply that utilities have different profitability expectations than other developer groups (see Appendix III). Third, more than two-thirds of the interviewees state that offshore wind projects in the UK offer sufficient profitability levels.[9]

Nonetheless, the notion that a project's profitability must correspond to its risks is a viable argument. The availability of alternative investment options with more favorable risk-return-ratios can be a hampering factor for expanding offshore wind power.

To more clearly understand the elements that drive project profitability, the analysis turns to developers' perspectives on the remuneration schemes and costs of offshore wind power.

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[9] The attractiveness of UK projects will be explored in more detail below; see also Finding 5.

Remuneration

Both the UK and the German government have increased subsidy levels for offshore wind power in recent years. This has been a reaction to rising development and construction costs and the continued high risk levels associated with offshore wind power.

In Germany, offshore associations have pushed for higher compensation levels (OFW et al 2010) to counter the sluggish expansion speed. To remain competitive with the British market and to ensure continued deployment toward the 2020 goals, the German parliament revised the renewable energy law[10] enacting the so-called acceleration model[11]. The intent of the acceleration model is to increase project profitability, while at the same time keeping the total level of subsidies constant (in nominal terms). This is achieved by accelerating, or "preponing", the bulk of revenue streams. The level of feed-in tariff is increased from 15 ct/kWh to 19 ct/kWh while the payout period is shortened from 12 to 8 years.[12,13]

This policy change constitutes an interesting case study of how specific implementation choices of energy policy instruments impact how firms perceive their attractiveness. Although formally the changes are minor—that is, offshore wind power is still remunerated with a fixed feed-in tariff under the framework conditions of the EEG and the total amount of subsidies does not change significantly—they have significant effects on (1) the profitability of projects, (2) the risk structure of projects, and (3) access to financing.

(1) The experts were asked whether they believe the acceleration model is an effective measure to overcome the above-identified barrier to expanding offshore wind power and whether it will help achieve the German goals for 2020. The result is somewhat ambiguous:

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10 German: Erneuerbare Energien Gesetz (EEG)

11 German: Stauchungsmodell, literally translating to "compression model" as the period of high cash flows is compressed.

12 The total sum of subsidies actually decreases. Compared to the previous law (15 ct/kWh for 12 years), a strictly linear 75% compression of cash flows would yield a tariff of 20 ct/kWh for 9 years. However, the time value of money needs to be considered. The OFW demanded 19.5 ct/kWh for 9 years, but finally the EEG set the tariff to 19 ct/kWh for only 8 years.

13 A detailed profitability analysis of the German acceleration model along with a comparison of several other European remuneration schemes can be found in Prässler and Schaechtele (2012).

Finding 4: The acceleration model will improve the profitability of OWP projects. There was no consensus among experts, however, whether this improvement is sufficient to realize the German 2020 expansion plans. Whereas utilities claim this step is too small, half of the respondents from other developer companies believe the new remuneration levels are sufficient.

Table 3 provides an overview of the experts' assessment, distinguished by type of developer company.

Table 3
Assessment of the German Government's Proposed Acceleration Model

Remuneration levels according to the proposed acceleration model are…	Company type				
	Utility	Municipality	Independent developer	SPV	**Total***
...sufficient.	0	1	1	1	**3**
...an improvement but less than required.	4	1	1	0	**6**
... not sufficient.	2	1	0	0	**3**

* One company (an ID) did not comment on this question.

Bearing in mind the limitations of a small respondent sample, the data seem to indicate a trend: Utilities seem to be less satisfied with the improvements of the new acceleration model than do the other types of developer companies. This might be because private utilities usually have higher profitability expectations than municipalities and small IDs. In addition, they usually have a wider range of alternative investment options, including other geographic regions and other power generating technologies.

(2) Some experts pointed out that the acceleration model also changes the risk structure of OWP projects. As the majority of investment costs need to be recuperated during the first eight years of the wind plant's lifetime, the level of risk with respect to the performance of the wind park and susceptibility to production fall outs increases during these early years.

(3) The acceleration model improves access to project financing and lowers its cost by better matching subsidy duration and loan duration[14].

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[14] To date, commercial banks have not accepted income streams after year 13 as security for loans in an attempt to limit risk exposure to a novel RET with lacking long-term performance records. As some projects were previously eligible for almost 17 years of feed-in tariff not all subsidized income streams could be used toward project financing and provide security to banks.

It can be concluded, that even seemingly small changes in implementing energy policy instruments can have significant effects on the companies at which they are directed.

Having analyzed the German remuneration scheme, we turn attention to policies implemented in the UK.

> Finding 5: Remuneration levels for OWPs in the UK are generally perceived as more attractive than those in Germany. In general, UK regulations pose barriers to market participation that favor large utilities over other types of developer companies.

In the UK, the primary deployment policy for producing renewable electricity is the renewable obligation certificate (ROC). This quantity-driven energy policy instrument allows the regulator to define the obligation for the required amount of national renewable electricity production and allows market forces to determine the certificate price on market exchanges.[15] Originally, one ROC was issued for each kWh of renewable electricity produced. As it became clear that developing more costly RETs stagnated, technology banding was introduced. Determined to establish global leadership in offshore wind power, the UK government subsequently increased the promotion level of offshore wind power from 1.0 to 1.5 ROCs in 2008, and in an additional step, up to 2.0 ROCs in 2009 (Toke 2010). High compensation levels, combined with favorable maritime resources, created an offshore wind power investment environment that is currently considered one of the most attractive in the world (Prässler & Schaechtele 2012; KPMG 2010; Ernst & Young 2011a).

The majority of the interviewed experts shared this prevalent opinion. Even after the acceleration model was introduced in the German EEG, the UK market offered the most profitable development conditions (see Appendix III). Still, the UK regulations create structural market entry barriers that prevent companies—especially municipalities and small IDs—from accessing the market. First, smaller companies tend to lack the capabilities to manage the certificate price volatility. Second, the complexity of the ROC

[15] Please refer to (de Jager & Rathmann 2008) and (Green & Vasilakos 2011) for a detailed explanation of the UK ROC scheme.

scheme may also constitute a barrier to companies that are not accustomed to it[16] (see Appendix III).

Empiric evidence from the British offshore industry mirrors these findings. Energy utilities are responsible for almost all the offshore wind power development activities in the UK.

Costs

> Finding 6: High costs are considered a major barrier for offshore wind power. Two aspects can be distinguished: (1) very large investment cost volumes, and (2) very high levelized costs of generating electricity.

The high costs of offshore wind power are an all-important issue among developers. Interviewees spontaneously mentioned “high costs” more often as one of the first two answers than any other topic (see Figure 1). Two separate cost dimensions and their distinct repercussions for offshore development need to be distinguished.

First, the absolute volumes of investment costs are enormous. The specific costs per KW capacity are higher than those of most other RETs, ranging between 3,300 and 4,500 EUR / KW according to the experts.[17] This does not yet include costs for connecting to the grid access points and potential extensions of the onshore grid system. Combined with the large plant sizes of up to 400 – 700 MW this translates into enormous total investment volumes, sometimes exceeding 1.6 billion EUR per OWP.

The second and arguably more important element of Finding 5 is that offshore wind power still has very high levelized costs of electricity generation (LCOE[18]). This puts offshore wind at a disadvantage compared to both conventional electricity generation and also other forms of RETs (see Figure 2).

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[16] This difference will be abolished soon as the UK ROC scheme will be changed into a FIT scheme (2013-2017: optional FIT; as of 2017 mandatory FIT)

[17] The IPCC SRREN report (IPCC 2011) quotes installation costs between \$3,200/kW – \$5,000/kW; KPMG (2010) found a range of 3300 EUR/kW – 3800 EUR/kW for German projects.

[18] The LCOE metric comprises all discounted lifetime costs incurred for producing electricity, including development, construction, operation, and decommissioning the plant spread over the total amount of electricity generated.

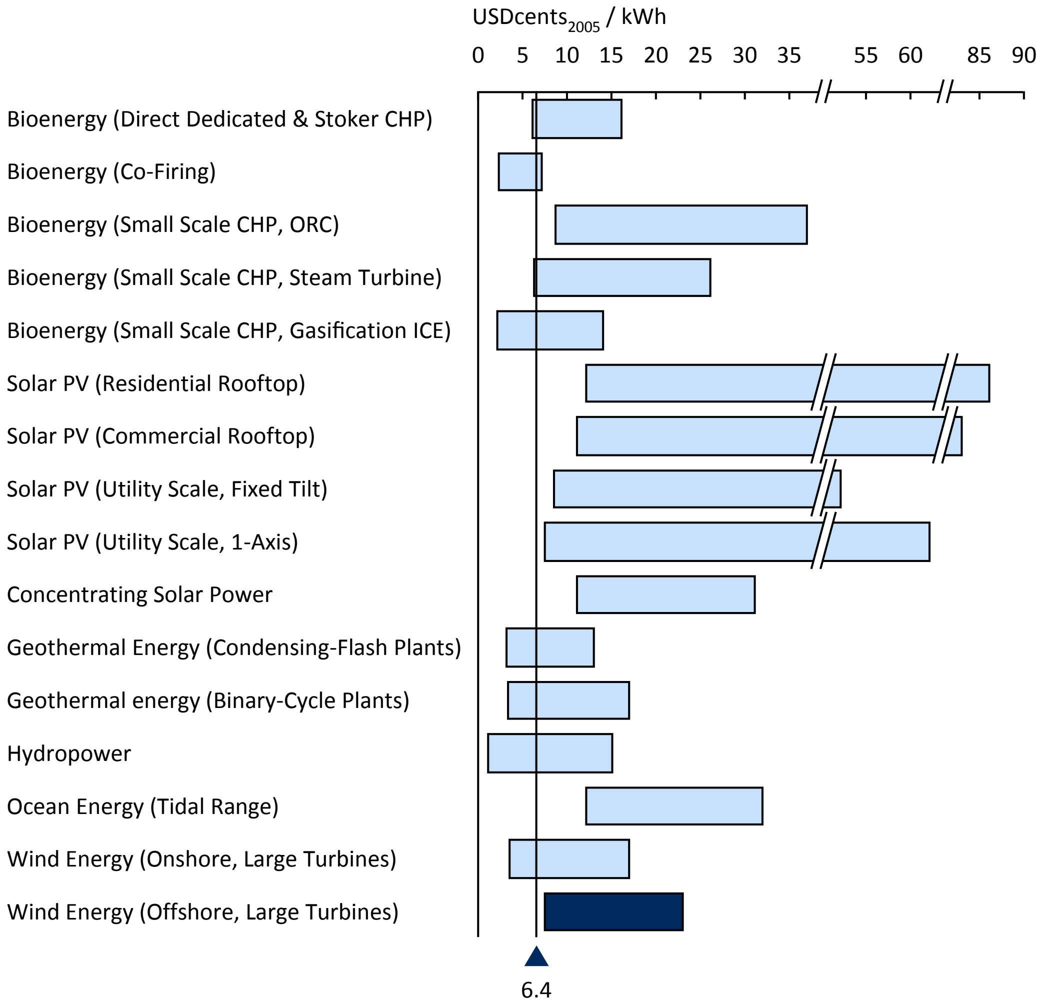

Figure 2: LCOE of RETs[19]. The average German wholesale electricity prices are shown as reference bar.
Sources: SRREN (IPCC 2011, p. 188), EEX (annual average base price October 2010 – October 2011: 5.1 EURcents/kWh)

As electricity from offshore wind plants is far from being competitive in electricity markets, it relies on high levels of subsidies. All experts consider this a key obstacle and highlighted that substantial advancements in cost reductions are pivotal for the future of development of the technology. They see potential for cost reductions in three areas: (1) technology innovations, for example through larger turbines; (2) economies of scale in both equipment production and higher utilization levels of infrastructure assets; and (3) increased competition in the supply chain.

19 Ranges indicate extreme case assumptions available in the literature. Low-end numbers assume the lowest values for discount rate, investment costs, O&M and fuel costs, and highest capacity factor and life times. High-end numbers represent the opposite.

4.3 Financing

Multiple types and sources of capital can be employed to shoulder the investment volume of an OWP.

Debt capital is provided by third parties and must be repaid under fixed, pre-defined conditions. So-called interest payments compensate debt issuers for the money service and the risks assumed. Debt is typically issued by banks.

In contrast, *equity* is capital that the owners of an asset (in this case the OWP) provide. It does not need to be repaid, but equity holders are entitled to a share of the profits of the asset. Typically, the risks for equity providers are higher than those of debt providers; consequently, they require higher reimbursement levels. Equity can be provided by different investor groups including operating companies, private equity funds, and institutional investors.

As for financing model, this study will focus on *project financing* and *balance-sheet-financing* for the sake of simplicity. In project financing arrangements both the project debt and equity are reimbursed entirely from the cash flows the project generates. Loans are usually not secured by the project sponsors, but by the OWP asset and all its contractual proceeds. The advantage for the sponsor company is that banks have little or limited recourse to the sponsors. The disadvantage is that financing is typically expensive, difficult to arrange, and lenders want to exert substantial operational control. In balance-sheet-financing, the sponsor company takes out a loan on the account of the entire company. The loan is thus reflected “on the balance sheet” of the company. It is typically easier to arrange and less expensive because it benefits from the creditworthiness of the sponsor company. The company carries all the risks of the OWP project, however, and the loan increases the debt burden of the sponsor’s balance sheet [see GERC (2008)]. Typically, balance sheet financing can only be done by larger corporations. (For a more detailed overview of capital types and financing models, see (Wiser 1997; Wiser & Pickle 1998; Langniss 1999; CPI 2011; de Jager & Rathmann 2008; UNEP & NEF 2009).

To this background, the results of the expert interviews suggest:

> Finding 7: Banks have been hesitant to provide debt financing for OWP projects as a result of the financial crisis and high technology risks. Loans tend to be relatively small and expensive.

The financial crisis of 2008 led to a global lending environment characterized by credit rationing, increased risk aversion among commercial banks, and more restrictive and thus more expensive lending terms. Financing of RET projects became more challenging than prior to the crisis (Schwabe et al. 2009). Figure 9 shows the stark contrast between surging compound annual growth rates (CAGR) in asset finance of almost 60% in the period 2004 to 2008 and a modest CAGR of 6% in the period 2008 to 2010.

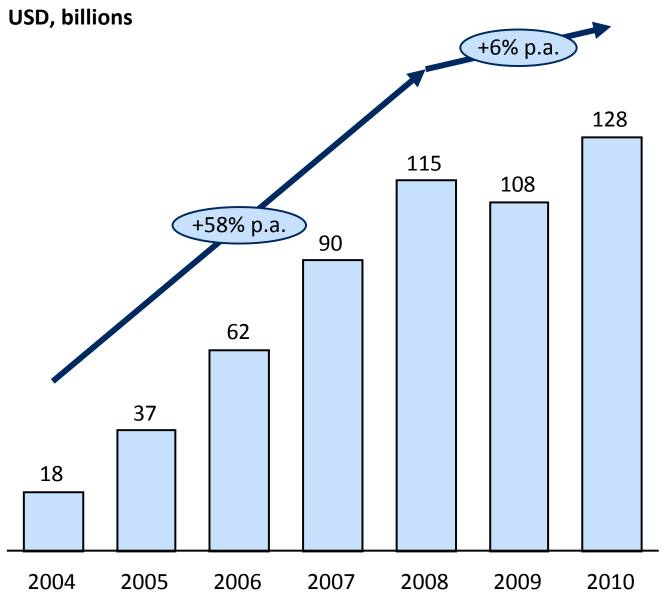

Figure 3: Development of asset finance for RET prior and during the financial crisis; bubbles indicate CAGRs Source: (UNEP & BNEF 2011)

In addition, banks cannot properly gauge the technology risks of offshore wind power because the industry has no long-term operational track records. Hence, there is an information asymmetry between lenders on the one hand and developers and operators of OWPs on the other. More than half of the interviewees said that this leads to an unusually high level of due diligence and risk scrutiny. The interview experts confirmed that against the backdrop of (1) the general credit rationing in the banking industry, (2) the specific technology risks, and (3) multi-contracting project structures, debt financing for OWPs is difficult to arrange and only available at rather unfavorable terms. This leads to three effects on loans under project financing arrangements.

First, lenders apply high average debt service cover ratios[20] of up to 1:1.35 or even 1:1.45 resulting in high equity requirements of up to 40% of the total capital requirements.

[20] The debt service coverage ratio is defined as the ratio of cash available for debt servicing to interest, principal, and lease payments. The above numbers relate to project financing arrangements in Germany.

Consequently, this limits the number of potential investors because not many companies can manage to provide such equity sums.

Second, lenders require very high risk premiums. Some interviewees quoted a 300-350 basis points premium differential compared to corporate bonds. Due to the high interest rates, there is practically no leverage effect that can be used in financing OWPs.

Third, banks only issue small debt tickets of up to 50 – 75 million EUR. Up to 15 to 20 commercial banks, therefore, are theoretically needed to accumulate the necessary debt financing volumes of roughly 1 billion EUR for a typical OWP.[21] According to many experts, however, there are currently only 12 to 15 banks in Europe that are capable and willing to finance offshore wind power projects.

This situation, however, is likely to improve in the future as technology-related risk premiums will fall, banks gain experience with OWP investments, and, in Germany, the new acceleration model accommodates lenders by shortening the repayment period and thus reducing risks.

The unfavorable conditions for project financing have led many companies to consider on-balance-sheet financing. This leads, however, to Finding 8:

> Finding 8: Different types of developers face different financing challenges. Whereas utilities can apply corporate on-balance-sheet financing, smaller developers need to resort to project financing.

Most utilities can issue corporate bonds at lower rates. They finance the OWP project on an equity basis rather than raising project financing loans. Whereas this approach allocates all of the project-related risks to the developing utility, it also makes it independent of the restrictions and conditions of banks. Smaller developers, on the other hand, usually do not have the capabilities to employ on-balance-sheet financing. This has implications for the competition among different developer types. Financing is a much greater barrier for municipalities and small IDs than it is for utilities (see Appendix III). Recently, several smaller companies started to employ alternative fundraising models such as issuing corporate bonds to private investors.

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21 Assuming a 400 MW project with total investment costs of 1.5 billion EUR and an equity ratio of 35%.

In sum, the currently prevailing financing environment can constitute a barrier for developing OWPs. European and national regulatory bodies have implemented financing support programs to overcome this barrier:

> Finding 9: Financing support programs are perceived as useful instruments that can help alleviate the financing challenge.

The experts mentioned two support instruments in the interviews: (1) the offshore initiative by the European Investment Bank (EIB) and (2) the Offshore Wind Power Program by the Kreditanstalt für Wiederaufbau (KfW). EIB funds essentially include a subsidy element because their interest rates are usually below the market level. Naturally, all developers see a positive impact of the EIB program for developing offshore wind power; for some it is indispensible (see Appendix III).

The KfW program does not entail a subsidy component but merely matches the conditions offered by commercial banks, yet provides large debt tickets of up to 500 million EUR[22] (KfW 2011). Most developers have welcomed the program,[23] saying it is very useful in times of credit rationing, improving opportunities for project financing.

> Finding 10: On an industry level, it will be difficult to secure the investment volumes needed to reach the 2020 development goals. Financial and institutional investors need to enter the market because energy companies will not be able to provide the necessary financing alone.

The task ahead is huge. Until the year 2020, investment volumes somewhere in the range of 113 billion EUR (conservative estimate) to 178 billion EUR are needed to build the registered European offshore wind power capacity (Ernst & Young 2011b). Currently, there is no consensus on whether the offshore wind industry will be able to attract sufficient funds to finance the industry's ambitious expansion goals.

Almost all experts agree that the traditional players in the power sector—large utilities and municipalities—will not be able to shoulder these investment volumes on their own (see

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[22] Including 100 million EUR for unexpected additional costs. The program is limited to 5 billion EUR total, therefore viable for the first ten projects that apply.

[23] Companies that are owned predominantly by the public, mostly German municipalities, are exempt from the KfW program. Offshore associations demand a level playing field, calling the exemption a *"unjustified and not inexplicable discrimination of this important developer group"* (OFW et al 2010, p. 13). One developer company in the interview sample cannot participate in the program because its project financing deal was sealed before the KfW program went into effect.

Appendix III). On a European level, investment volumes of annually 20 billion EUR for the next 20 years (according to J1) would be required to develop offshore wind power alone—a sum that is likely to overextend energy companies. Some German utilities claim that *"Ironically, the nuclear phase-out in Germany limits the financing power that big utilities have to invest in offshore wind power"* (B1). This ties in with findings from a recent report by the European Climate Foundation which claims that *"There is not enough capital available from the active actors in the power sector in the current system to meet decarbonisation targets"* (ECF 2011, p. 8).

Notably, offshore wind power is not the only industry with huge investment requirements in the decade to come. The transformation of the European energy sector is a tremendous financial undertaking. The ECF (2011) estimates that 1.3 trillion EUR will need to be invested in power transmission and generation systems over the next 15 years, doubling the historical investment rate. Both the report and the interview experts agreed that it is absolutely mandatory to find additional funding sources. According to the interviewees, these could be private equity funds, institutional investors such as sovereign wealth funds and pension funds, as well as commercial banks.

To date, offshore wind power projects have not attracted much funding from these investors, but many of the experts are convinced that this will change in the near future. The characteristics of OWPs are a good match for the investment appetite of institutional investors: long investment horizons corresponding well with the lifetime of the power plants, stable revenue streams (especially when backed by FITs), and minimal risks and costs during the operational phase. Furthermore, OWP projects allow for very large tickets, unlike some other RET projects (see Appendix III). The first companies from the financial sector are starting to become engaged, ranging from insurers (Reuters 2011) to pension funds (Bloomberg 2011) and even private equity companies[24] (Blackstone 2011; Financial Times Germany 2011). According to the experts, three things are essential to sustain this trend: (1) generating a positive operational track record of operating OWPs; (2) a stable financial market environment; and (3) regulators sending out supportive signals for offshore wind power and ensuring stability of the support schemes.

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[24] Between the time of interviews and the time of writing, three private equity companies invested in German OWPs: Blackstone, Ventizz, and Brancor.

4.4 Grid connection

Grid regulation is perceived as a key barrier in developing offshore wind power. In the opening question on barriers, this topic received the second most spontaneous mentions among the Top 5 issues (see Figure 1). Interestingly, all of these responses referred to German OWPs projects; none to British. The root of this noteworthy discrepancy and its repercussions on developers is analyzed in the following.

> Finding 11: Responsibility for providing the grid connection for OWPs is regulated differently in Germany and the UK: Whereas in Germany the TSO is in charge of providing and paying for the grid connection, in the UK the developer companies assume these responsibilities. This poses different challenges for developers and necessitates different skill sets.

In Germany, §17 Abs. 2a of the German Energy Act[25] obliges the TSO to provide grid connections for offshore wind power plants by the time the plant is operationally available. The TSO assumes all costs for the connection up to the offshore transformation platform[26]. According to the experts, this regulation is well-intended because it facilitates market access for non-utility companies that usually do not have the capabilities to build grid connections. At the same time, it enables the TSO to aggregate multiple OWPs into a combined grid connection.

Almost all of the experts, however, complained that this setting significantly complicates the project development process because a third party is involved. The interaction between the TSO and developer creates difficult interfaces in project management, which necessitate day-to-day coordination for many commercial, technical, and legal aspects. In particular, the interviewees criticized the loss of operational control, and the adverse implications for scheduling and time planning.

In the UK regulations are inverse: Developer companies are in charge of grid connections for OWPs and also bear their costs. After completion, the transmission asset is sold to an offshore transmission owner. The experts consider this approach to be much simpler. It allows for a more integrated approach to project and time management and eliminates the need to collaborate with third parties. Developer companies, however, must shoulder

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[25] German: Energiewirtschaftsgesetz (EnWG)

[26] This is usually referred to as the “Steckdose auf See,” the power outlet at sea.

a larger task: in addition to higher financing requirements, they also must have a wide set of additional technical capabilities to establish the grid connection. This may put small developer companies at a disadvantage and favor utilities. From a societal welfare perspective, it creates a structural risk of redundancy where separate connections for OWPs amount to higher costs and a more severe impact on the environment.

Both regulations have their advantages and disadvantages (see Appendix III) and result in different consequences for developer companies.

> Finding 12: The German grid regulations have created major planning risks. The main risks arise regarding timing issues and the lack of legal certainty.

§17 Abs. 2a of the German EnWG has been the source of serious risks for offshore development projects. Some experts complained that *"Grid connection has emerged as the number one risk for OWP projects because it is not in the sphere of influence of the developer. It is a black box"* (A1). This perception relates to chicken-and-egg-problem: Before the TSO assumes the commitment to provide a grid connection, it needs to be assured that a planned OWP will be realized with certainty. The TSO, therefore, previously required developer companies to provide credible proof in the form of finalized financing arrangements and signed turbine order contracts. The developer companies, on the contrary, have difficulties providing these arrangements without the TSO's definite commitment to provide the grid connection for the planned OWP.

This situation has created considerable ambiguity on both sides, leading to legal uncertainties and delays in the development process. Long lead times of roughly 30 to 40 months for constructing the grid connection have led to costly delays and have further aggravated the issue.

In response, the Bundesnetzagentur[27] published a position paper in 2009 (Bundesnetzagentur 2009) aimed at untying this Gordian knot. It provides guidance by defining criteria that developer companies must fulfill in order for the TSO to initialize the connection.[28]

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[27] German grid regulation authority

[28] Four criteria: (1) valid permit issued by competent authority, (2) plausible construction plan, (3) complete construction ground assessment, and (4) pre-orders of turbines or sealed financing for turbine ordering, conditional on grid connection commitment. To trigger a connection investment decision criteria 1-3 or 1, 2, and 4 need to be fulfilled.

Most interview experts welcomed the position paper, saying that it helps clarify the situation to some extent, however, not yet solving it conclusively[29]. Interestingly, many developers acknowledged that the majority of the risk is now shifted from the developers to the TSOs (see Appendix III).

Another problem is the uncertain legal status of the position paper: it is merely a guidance communication—not a binding law. In case of a conflict, developers cannot legally enforce their rights. For example, the TSO is granted 30 months to provide the grid connection but in practice this has been or will be exceeded for most of the German OWPs under development (see Appendix III).

As a consequence of these uncertainties, the grid connection process has been a bottleneck for many German OWP projects. It binds resources, it is expensive, and it creates risks of running into contractual penalty fees (for both the developer companies and the TSOs). Without exception, all of the experts agreed that the speed of connecting to the grid needs to increase.

Another issue that impedes the speed of grid connection in Germany is rooted with the TSO:

> Finding 13: In Germany, the capabilities and resources of the TSO are stretched under the current regulation, causing delays in connecting to the grid.

In theory, centralizing the responsibility for offshore grid connections with the TSOs allows for strategic, consistent planning to extend the offshore grid and to avoid redundancies. In practice, this can overwhelm the operational and financial resources of single TSOs. Because many developer companies drive their development projects simultaneously, TenneT—the TSO responsible for OWPs in the North Sea—is now required to prepare nine connections in the legally defined timeframe of 30 months. The overload leads to delays for practically all of these projects (Süddeutsche Zeitung 2011). Recently, TenneT wrote an alarming complaint letter to German officials: *"…informing them that the construction of connecting cables for offshore wind farms in the North Sea is no longer advisable and possible under current conditions and in the current speed."* (TenneT 2011). The experts

[29] The fact that a second position paper (commenting on the first one) was issued in 2011 backs this view (Bundesnetzagentur 2011).

consented with this assessment, acknowledging that TSOs such as TenneT *"…face a rush of applications that they need to work on. This puts a severe strain on their capacities"* (D1).

To conclude, regulating grid connections in Germany is complex, time consuming, and places a strain on the resources of the developers, TSOs, and public authorities involved.[30] In contrast, in the UK, the responsibility of connecting OWPs to the grid is shouldered by each individual developer company. Here, close collaboration among developer companies is needed to avoid redundancies and enable learning from best practices.

[30] Despite these challenges, grid connection progresses: four parks are connected and applications for greater than 2 GW capacity are made; more than in the UK.

4.5 Administrative processes

The term "administrative processes" describes all interactions between developer companies and the competent authorities involved in developing an OWP. The more complex, lengthy, and arduous the process, the larger the administrative barrier is to overcome and the more expensive the final OWP will be.

Offshore wind power projects tend to be long and highly complex endeavors. They can take up to 8 to 14 years, involve up to ten different main authorities plus many more subordinate authorities, and require several thousand pages of documentation. The project schedule chart in Figure 4 is exemplary only, following the process in Germany. Both the sequence of tasks, milestones, and respective timelines may vary from country to country and for each specific development project. The arrows indicate the multiple interdependences among the project steps. Delays in one step usually entail delays in subsequent steps.

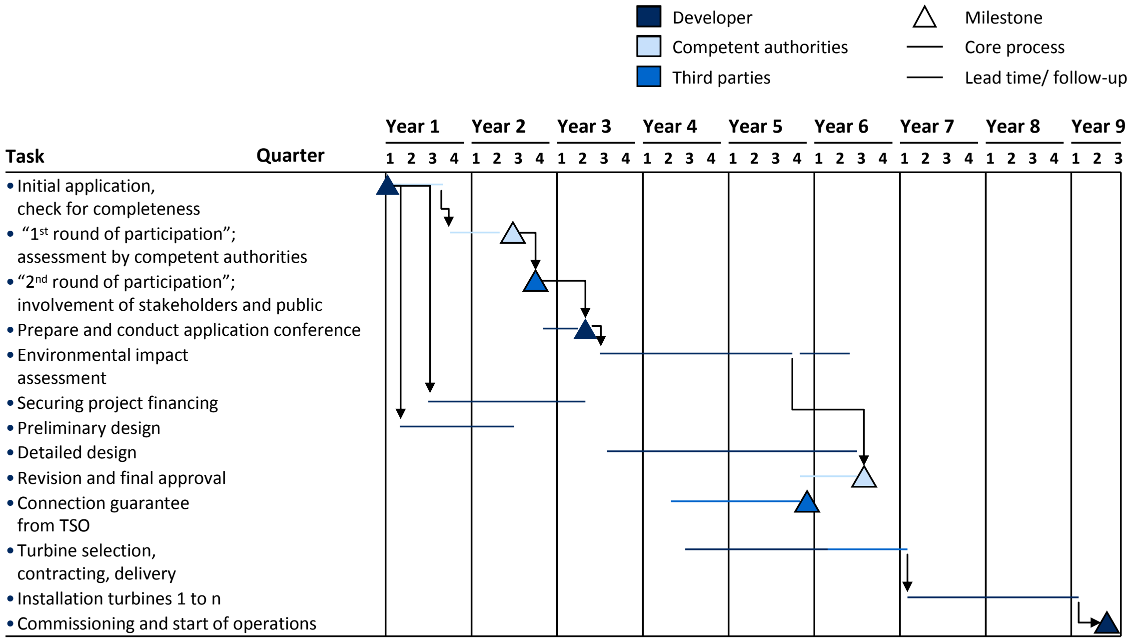

Figure 4: Stylized project schedule[31] for an offshore wind power development project
Sources: Interviews, Bundesamt für Seeschifffahrt und Hydrographie (BSH) (2005; 2007), Principle (2010)

Overall, developers perceive several issues related to administrative processes as barriers to expanding offshore wind power. Referring to the opening question of the interviews (Figure 1), experts mentioned issues such as "unclear and unreliable development standards," "environmental regulations," "authorities: limited resources and lack of will,"

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[31] For the sake of clarity and comprehension, many additional steps and third parties are omitted.

and “safety regulations” as barriers. In total, these issues represent almost 40% of all mentions the experts uttered.

> Finding 14: The novelty of offshore wind power leads to many unprecedented regulatory issues. Authorities need to develop reliable standards to eliminate risks and uncertainties.

When developing offshore wind power both developer companies and authorities break new ground. Applicable reference cases are often scarce and thus novel solutions need to be developed. The interviewees reported that in many cases both milestones and the requirements that need to be met to fulfill them are not defined properly. The lack of clear regulations often results in project delays. The experts highlighted the enormous costs associated with these delays, including penalties, refinancing costs, profitability slumps because of delayed revenues, and also the risk of moving into a less favorable EEG-tariff (see Appendix III).

The developers expressed wide consensus that defining reliable standards is of paramount importance for eliminating the planning uncertainty (see Appendix III). Authorities need to translate lessons learned into reliable, legally binding regulations to enable smooth development processes.

According to the experts, this task is especially challenging for Germany. Other countries such as the UK, Denmark, or The Netherlands have offshore industries (e.g., oil and gas exploration) and thus have administrative structures and basic guidelines for offshore operations at their disposal. On the contrary, German authorities have virtually no experience with offshore operations. The interviewees suggested two measures to facilitate a learning process.

First, the German administration could leverage existing regulations from other countries more extensively. According to the interviewees, there is too much reluctance to adopt foreign regulations as authorities strive to create their own. Second, new standards will be more effective when they are developed by collaborating with developer companies. The latter can contribute valuable information to how regulations take effect in practice and can help identify unwanted second order effects.

> Finding 15: General attitude of authorities, openness, and transparency are important elements to create trust among developers. Authorities in the UK perform better along those lines than German authorities.

The complexity of the process and the lack of standards in permitting regulations create risks for development companies. Whether they perceive these risks as significant barriers depends to a large degree on the quality of collaboration with authorities. There is a very high, yet intangible value to authorities' conduct. Aspects such as transparency, a positive can-do attitude, and willingness for constructive, goal-oriented collaboration can go a long way in reducing perceived risks.

All expert interviewees that have development experiences in both the UK and Germany reported that the UK authorities convey these characteristics much better than the German authorities. This becomes evident in (1) consistent stance toward offshore wind power from the highest strategic level down to the lowest working level; (2) a positive, welcoming attitude toward offshore wind power; and (3) transparent regulatory processes in the UK (see Appendix III). Regarding the latter, the Office of Gas and Electricity Markets (Ofgem) and the Department of Electricity and Climate Change (DECC) generally send out information letters to developers, regularly conduct joint consultations, and give early warning signs when regulations change. As a result, developers feel informed and have time to react.

In Germany, the BSH is the main point of contact for development regulations. Many of the subordinate authorities only communicate via the BSH such that the number of interfaces for the developer companies is reduced. German developers have mixed feedback regarding this process. Half of the interviewees called for better coordination, a clearer structure, and an even stronger bundling of competencies under the control of a single one-stop-shop. Others complained about the loss of control and would favor a more direct engagement with subordinate authorities. Remarkably, all the interviewees agreed that the BSH is very constructive and positive in collaborating. Other authorities such as the Bundesamt für Naturschutz (BFN) or the Bundesamt für Materialforschung (BAM)[32] are not seen as positive. Seemingly arbitrary rejection criteria, changing responsibilities, and redundant certification processes were among the issues mentioned in the interviews.

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[32] BFN – Federal Agency for Nature Protection; BAM – Federal Institute for Materials Research and Testing

Developers pointed out that the quality of service and collaboration is impacted by workforce constraints. Relevant authorities lack person-power and sometimes expertise to cope with the work load; employee turnover is high. Consequently, developers face ever-changing contact persons and the authority loses relevant knowledge and speed. Organizational learning is hampered. Low-cost actions such as providing authorities with adequate person-power may pay for themselves manifold by reducing overall development costs for society. All these measures help inspire confidence among developers and investors.

> Finding 16: Environmental regulations create a high hurdle for developing offshore wind power, in Germany more so than in the UK.

More than two-thirds of the interviewees raised the issue of environmental regulations in the course of the interviews as they are often the cause for delays and additional expenses. They all agreed that this effect is more pronounced in Germany than in the UK. There are three aspects that lead to this finding.

First, environmental regulations themselves are significantly stricter in Germany than in the UK. The most prominent example is ramming noise protection.[33] In Germany, the regulators impose maximum noise thresholds that ought not to be exceeded during construction of OWPs. With current state-of-the-art technology, however, these noise levels cannot be abided. This has caused delays and creates a high barrier for developers (see Appendix III). Second, there is structural conflict of responsibilities in the German administration process between the BSH and the BFN. The approval of the latter is inalienable for OWP development projects to receive the final go ahead. Third, in Germany there have been ex-post amendments to environmental protection regulations that surprised companies during the course of project development. All experts agreed that ex-post changes are detrimental to project planning and can entail high additional costs that are not directly linked to the environmental protection: *"New regulations for new species are not a problem for developers as long as they are communicated well in advance and foreseeable. It's surprises that can be deadly"* (F1).

[33] Maritime mammals such as the harbor porpoise can be injured severely by the extreme noise levels that result from ramming monopile foundations into the ground. One possibility to protect them is to blurt out loud warning sounds prior to ramming to scare the animals away. This is also forbidden, however, by German environmental regulations. A protection time window from May to August is being discussed. Unfortunately, those are also the key months with favorable weather conditions and thus critical for offshore wind construction.

When interpreting these views on environmental protection regulation, note that a stakeholder bias may be at play. Naturally, there is a conflict of interests. While the first priority of developer companies is developing offshore wind projects quickly and smoothly, administrative bodies and environmental associations have an interest in providing maximum protection to existing ecological habits.

Sensible environmental regulation must strike a suitable balance between these two objectives. Interestingly, the conflict does not seem to emanate from the rules that ensure environmental protection but rather from the way they are introduced and enforced. With the exception of ramming noise protection, developers are hurt most by the last two of the three aspects identified above: conflicting responsibilities between different authorities and ex-post amendments to existing regulations without due notice.

4.6 Legal security

In the context of this analysis, the term legal security refers to the stability and reliability of all regulations related to deploying offshore wind power and its legal enforceability in courts. In general, legal security is an important aspect for developing RETs (Lüthi & Prässler 2011). It cuts across most of the other topics and has surfaced in many discussions on grid connection, remuneration schemes, and permitting procedures.

> Finding 17: Long-term reliability and stability of primary deployment policies is of upmost importance. Due to very long construction times and huge investment sums, this is even more important than for other RETs.

All experts agreed that the stability of the primary support scheme is absolutely crucial for developers and investors to engage in developing offshore wind power. While most interviewees do not fear declines similar to recent subsidy cuts for solar PV[34] many stressed, however, that the repercussions of an analogue development would be much more severe for offshore wind power. OWPs are much more expensive by a factor of 25x to 60x and require planning and construction lead times of roughly 10 years as opposed to one. Consequently, the associated risks with respect to regular subsidy revisions are much higher. If policy regulators want to make changes to primary deployment policies, they need to communicate them well in advance and assess all potential repercussions on investors in joint talks. In fact, policy makers in the UK currently provide a positive example

[34] E.g., introduction of capacity caps in Spain in 2008 (Kirkegaard et al. 2010; Kreycik et al. 2011); unscheduled FIT reductions in Germany (BMU 2012)

of how this can be executed. As of 2017, the ROC scheme will be changed to a FIT scheme[35] (DECC 2011). Although this represents a fundamental disruption to the primary support scheme, *"…companies are not too worried. The UK government is very cautious, engaging and keeps stakeholders well-informed. Most changes seem to be improvements anyway"* (E1).

> Finding 18: The uncertain legal status of provisions regulating the permitting process increases risks for developers. Furthermore, limited legal enforceability undermines the confidence of developers and lenders.

This finding is linked closely to Finding 14. Many standards still need to be defined to increase clarity regarding the permitting procedure. According to the experience of the experts, *"…arrangements often lack reliability. Authorities only give oral statements or meeting write-ups instead of official, written statements"* (L1). Many interviewees complained about lacking or inadequate timelines in the permitting procedure. One project manager noted that there is a *"…legal vacuum in scheduling: we need legally binding response times from authorities, clear time windows and deadlines"* (F1).

Quite understandably, the level of uncertainty among authorities is also high. If they commit to legally binding regulations at this point in time, they run the risk of complex consequences in case they must revise them later. Nonetheless, as the industry matures, loose arrangements and position papers need to be replaced by transparent and binding standards. In the absence of the latter, legal risks associated with ill-defined regulations currently lie with the developer companies. As lenders and investors are reluctant to assume such legal risks, they usually require guarantees or expensive insurance, which increases the overall costs of project development. This is yet another example of how risks translate into unnecessary transaction costs in deploying RETs.

> Finding 19: Unanticipated changes to regulations in the permitting process are a major source of uncertainty for project developers. Resulting project delays amplify the detrimental impact of changed requirements in terms of time and costs.

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[35] From 2013 to 2017, companies will be able to choose between the legacy ROC scheme and the new FIT scheme. After 2017, the FIT scheme will be mandatory.

According to the experts, several ex-post amendments have been added to the catalogue of requirements in the permitting procedure. The list includes changes to safety security regulations, ground testing procedures, lighting regulations, and noise protection. These changes caused major complications for project planning and scheduling (see Appendix III). Experts stressed that any regulations can be managed as long as they are predictable, but that unforeseen changes are difficult to manage.

Two key aspects emerged from the analysis. First, developers need to have confidence in the long-term stability and reliability of the underlying deployment policy instruments for offshore wind power. Second, the procedure and regulations that govern the permitting procedure need to be transparent, reliable, and enforceable. This is a clear assignment to policy makers and relevant authorities. Improving legal security is a key measure to improve both the effectiveness and the cost efficiency of offshore wind power policies.

4.7 Human resources

Shortage of human resources is an important aspect that emerged during the interviews:

> Finding 20: A shortage of skilled human resources slows down the expansion of offshore wind power.

The lack of skilled personnel for both developer companies and regulatory authorities is a bottleneck. For developers, the key challenge is to find people with enough industry-specific expertise. For public authorities, it is just as much a matter of quantity as of quality. Many departments are understaffed and cannot cope with the work load at hand (Appendix III). Regulators could alleviate this situation by providing additional jobs and professional retraining. Introducing more dedicated university courses and educational training have been suggested as worthwhile measures to preempt even more severe skill shortages in the future.

> Finding 21: The industry will likely miss official government deployment goals for 2020 in both the UK and Germany.

Most of the interview experts believed that the 2020 goals in both Germany and the UK will be missed. This finding may well be a direct result of the sum of all the barriers identified above. Several experts stated, however, that the resource bottleneck alone constitutes a large enough barrier to speedy capacity additions. So, even abstracting from topics such as financing, grid access, or profitability levels, *"…the 10 GW in Germany in 2020 are not realistic!"* (B1, see Appendix III for further statements). Similarly, the ambitious goals of the UK government of 13 GW (or even 18 GW in case significant technology cost reductions should materialize) seem in jeopardy according to most of the interviewees.

Sources outside the expert panel, however, paint a more positive picture of the abilities of the offshore wind industry. For example, the German offshore wind power association is optimistic that the government's goals can be reached, calling the goals *"ambitious yet possible. However, only if the political framework is right."* (Windenergie Agentur, 2011).

5 Conclusions

The above findings (summarized in Appendix I) touch on myriad aspects that foster or impede the expansion of offshore wind power. Adopting the perspective of developers, they can be condensed into three decisive determinants: (1) project profitability, (2) level of risks assumed by developers, and (3) complexity and speed of the development process.

(1) Experts are in disagreement whether recently improved profitability levels will be sufficient to propel deployment of offshore wind power as desired. There is consensus, however, that UK OWP projects are more profitable than German projects. This is partly because of the longer duration of support and partly because of lower development costs. For the future of offshore wind power, significant technology cost reductions will be crucial in the mid- to long-term.

(2) Profitability levels need to correspond to associated risks. Currently, the risk-return-ratios of other, low-risk RETs such as onshore wind or solar PV are more attractive than offshore wind power. Instead of increasing return levels—a measure prominently discussed in public and political debates on renewable energy support—reducing risks is an equally important task that regulators need to address.

The largest sources of risks in developing offshore wind power are grid connection regulations, the lack of standards and ill-defined timelines for permitting requirements, and legal uncertainties. To reduce these risks, regulators need to define clear and reliable standards that are sufficiently stable and legally binding.

The analysis indicated that many risks are “perceived” risks. Developers and lenders require real risk premiums for any risk source that—in their perception—could lead to project delays and unforeseen costs. These risk premiums increase the cost of developing offshore wind power. Thus, it is important for energy policy makers and functional authorities to not only remove risks, but also change the perception of risks. They need to create trust and confidence among developer companies. To this end, a collaborative, can-do attitude, engaging permitting processes, and the willingness to reach practical compromises on challenges that arise are valuable intangible assets. The analysis shows that (1) the UK’s policy regime performs better on these dimensions than the German regime, and (2) these assets can be instrumental in increasing the effectiveness and efficiency of deploying offshore wind power. Furthermore, they tend to be relatively cost-effective to implement.

(3) The notion of reliability emerged as particularly important to developers, because various ex-post changes and additions to permitting requirements resulted in unforeseen and costly delays in project planning. Administrative processes could also be improved by reducing the number of authorities involved and improving the coordination among them. Clustering competencies in a one-stop-shop concept could be a feasible approach. Furthermore, providing more human resources seems like a small investment with potentially high societal payback in form of significantly lower deployment costs.

The analysis seconded the argument of Langniss (1996) that investor and developer companies are not a homogenous group but differ by type, size, capabilities, and motivation for engaging in developing offshore wind power. The analysis indicates that the barriers for small, IDs are higher in the UK than in Germany, especially regarding their view on regulating grid access, the lack of financial support instruments, and the more complex and volatility-prone remuneration scheme. In all of these areas, policy design choices impact the competitive landscape for different types of developer companies.

As Wüstenhagen and Menichetti (2012) pointed out, the devil lies in the details when it comes to energy policy design. For offshore wind power, developers do not show a fundamental preference for either type of primary deployment policy (FIT or ROC system). However, seemingly small aspects do matter: The introduction of the acceleration model in the German FIT for offshore wind power and the different specifications of the grid access regulation in Germany and the UK are good examples. When designing the implementation specifics of policy instruments, it is helpful for policy makers to adopt the perspective of the developer and investor companies to understand all repercussions in the market.

Finally, the analysis shows that the 2020 development goals for offshore wind power could be in danger for both the UK and Germany. Most interview partners argue that due to the long lead times for project development it is already foreseeable that the goals might be missed. The reasons for this are manifold. Most prominently, surging technology costs and the resulting low profitability levels have been key barriers thus far. Further bottlenecks could be persistently strained financing markets; high regulatory risks in the permitting procedure; the general shortage of experienced personnel for both developers and authorities; and the immaturity of the construction supply chain. Of course, hope is not lost for this promising alternative energy. Offshore wind power is still a young, high-growth industry, and most of these barriers are currently improving. The performance of the offshore wind power industry in the second half of this decade will be decisive for determining how much capacity can be deployed by 2020.

Researcher should keep monitoring this development and derive best-practices-approaches for regulating and administrating offshore wind power deployment. Those insights will provide valuable guidance for other European countries.

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Appendix I—Overview of Findings from Expert Interviews

Topic		Finding
Importance of barriers	# 1	The most salient barriers to offshore wind power development are: (1) unclear/unreliable development standards; (2) risks related to grid access regulations; (3) insufficient remuneration levels; and (4) high costs.
Profitability, Remuner-ation and Costs	# 2	The level of expected profitability is one of the most important drivers for the development decision. At the same time, it is currently perceived as one of the main barriers for developing offshore wind power.
	# 3	Offshore wind power offers a less attractive ratio of risk and return than more established RETs such as onshore wind and solar PV.
	# 4	The acceleration model will improve the profitability of OWP projects. There was no consensus among experts, however, whether this improvement is sufficient to realize the German 2020 expansion plans. Whereas utilities claim this step is too small, half of the respondents from other developer companies believe the new remuneration levels are sufficient.
	# 5	Remuneration levels for OWPs in the UK are generally perceived as more attractive than those in Germany. In general, UK regulations pose barriers to market participation that favor large utilities over other types of developer companies.
	# 6	High costs are considered a major barrier for offshore wind power. Two aspects can be distinguished: (1) very large investment cost volumes, and (2) very high levelized costs of generating electricity.
Financing	# 7	As a result of the financial crisis and high technology risks, banks have been hesitant to provide debt financing for OWP projects. Loans tend to be relatively small and expensive.
	# 8	Different types of developers face different financing challenges. Although utilities can apply corporate on-balance-sheet financing, smaller developers need to resort to project financing.
	# 9	Financing support programs are perceived as useful instruments that can help alleviate the financing challenge.
	#10	On an industry level, it will be difficult to secure the investment volumes needed to reach the 2020 development goals. Financial and institutional investors need to enter the market because energy companies will not be able to provide the necessary financing alone.

Appendix I—Overview of Findings from Expert Interviews (continued)

Topic		Finding
Grid connection	#11	Responsibility for providing the grid connection for OWPs is regulated differently in Germany and the UK. Although in Germany the TSO is in charge of providing and paying for the grid connection, in the UK the developer companies assume these responsibilities. This poses different challenges for developers and necessitates different skill sets.
	#12	The German grid regulations have created major planning risks. The main risks arise regarding timing issues and the lack of legal certainty.
	#13	Capabilities and resources of TSOs are stretched under the current regulation, causing delays in grid connection.
Administra-tive processes	#14	The novelty of offshore wind power leads to many unprecedented regulatory issues. Authorities need to develop reliable standards to eliminate risks and uncertainties.
	#15	General attitude by authorities, openness, and transparency are important elements to create trust among developers. Authorities in the UK perform better along those lines than German authorities.
	#16	Environmental regulations create a high hurdle for developing offshore wind power, in Germany more so than in the UK.
Legal security	#17	Long-term reliability and stability of primary deployment policies is of upmost importance. Due to very long construction times and huge investment sums, this is even more important than for other RETs.
	#18	The uncertain legal status of provisions regulating the permitting process increases risks for developers. The limited legal enforceability undermines confidence of developers and lenders.
	#19	Unanticipated changes to regulations in the permitting process are a major source of uncertainty for project developers. Resulting project delays amplify the detrimental impact of changed requirements in terms of time and costs.
Human resources	#20	A shortage of skilled human resources slows down the expansion of offshore wind power.
	#21	The industry will likely miss official government deployment goals for 2020 in both the UK and Germany.

Appendix II—Interview Guide for Semi-structured Expert Interviews

Interview Guide

The information obtained during the interview will be used only for the dissertation of Thomas Präßler, PhD candidate at PIK. All information will be treated confidentially; company names will not be disclosed. The interview will focus on regulatory aspects of developing offshore wind power. The key research question is how regulators can best employ policy instruments—from the developers' perspective—to foster the development of offshore wind power. Please assume that publicly available information on the project(s) is known; thus, the interview will focus on the "inside perspective" of the development process.

1) Background information on the interviewee

- The Company
  - Level of experience in developing offshore projects.
  - Bandwidth of activities in development process (e.g., early stage development, acquisition of financing, management of construction (in-house or multi-contracting), operation).
- The Interviewee
  - Personal background, level of experience with offshore wind power.
  - Position, tenure in company, involvement in project development.

2a) Drivers and barriers of offshore development – open section

- What are the most significant regulatory barriers to developing offshore wind projects? Please name up to 5.
- What were the key determinants of the location decision? How was the screening process conducted?

2b) Drivers of and barriers to offshore development – attributes from onshore study:

- Remuneration / Profitability
  - How important were remuneration levels for past and future investment decisions?
  - How can policy changes help improve revenues? What about project profitability?
  - For Germany: What is the effect of the new Stauchungsmodel?
  - What are key cost drivers? Which of these can the regulator influence?
- Credit financing support
  - Does financing constitute a road block for offshore development? Now versus the next five years?
  - Which effect does the new KfW program for offshore wind power have?
- Cash grants
  - Are cash grants available for offshore development projects (EERP, NER300)? How important are they for driving investment?
- Grid access regulations
  - What are the main regulatory barriers regarding grid connection?
  - Will limited onshore grid capacity be a factor for your company's offshore development activities?
- Administrative processes
  - How long did the administrative processes take? Were they well structured?
  - How many authorities were involved in all the permit procedures?
  - How was the overall attitude of the authorities?
  - What could be done to improve administrative processes?
- Legal security
  - How big a factor is the reliability of primary deployment policies?
  - Have there been any obstacles caused by legal uncertainty during the development process? Which ones?
  - How important is the aspect of "legal security" for the site decision?

2c) Drivers and barriers of offshore development – other aspects

- Is the availability of expertise and personnel a bottleneck for future development activities? What can the regulator do?
- Are there any aspects of importance that we have not yet discussed?

Appendix III—Quotes

Exemplary statements about profitability and remuneration schemes of offshore wind projects

Topic	Exemplary Quote	Expert Interviewee
Profitability	*Return levels need to correlate with the level of risks assumed. Profitability is clearly less than 10% unlevered. Compared to 8% for a solar park that contains little risks and proven technology this is not enough to warrant investments in offshore wind.*	C1 (utility), Manager in Offshore Department
	Profitability levels for offshore wind parks in Germany are sufficient… Utilities might have a different view on this because they generally have higher profitability expectations.	J1 (independent developer), Technical Project Manager
Remuneration	*The proposed acceleration model definitely goes into the right direction. However, the improvement is less than what we hoped for and expected.*	A1 (utility), Head of Offshore Department
Acceleration model in Germany	*Profitability is ok with the acceleration model. It improved the situation and we are confident, that this new scheme will ensure investments in German offshore wind projects.*	M1 (SPV), Technical Project Manager
	The proposed remuneration under the acceleration model is still not sufficient. Following our request of 9 years and 19.5 ct/kWh would have been better… It remains to be seen if this will dry up the project pipeline or not.	I1 (municipality), Commercial Project Manager
Remuneration in UK	*Level of remuneration is the most decisive factor for us…and FIT are better for smaller companies because we cannot manage fluctuating market elements. The acceleration model is very effective but still not enough to close the gap to the UK, the bold move is lacking.*	K1 (independent developer), Head of Offshore Department
	Currently the UK is more profitable but the UK Round 3 projects will not be much better than projects in Germany.	B1 (utility), Manager in Offshore Department
	We can get better profitability in the UK. They are world market leader in offshore and want to keep that status, the expectation is that the UK will always react to support systems in other markets (as they have done in the past) so that they remain the most attractive offshore market.	D1 (utility), Head of Offshore Department

Exemplary statements about cost levels of offshore wind power development projects

Topic	Exemplary Quote	Expert Interviewee
Costs	*Investment costs are too high in GER due to the large distance to shore. Also, costs have been underestimated. Secondary costs such as security facilities, ground testing, lighting etc. add up and were unforeseen.*	G1 (municipality), Commercial Project Manager
	Investment costs need to come down – there is little the regulator can do about it. Suppliers currently grab monopoly rents…as of yet, there is little competition and little economies of scale.	B1 (utility), Manager in Offshore Department
	We suffer from unforeseen cost overruns which lead to diminishing economics of project. Many costs are on top of what was learned at the Alpha Ventus test field.	H1 (municipality), Head of Offshore Department

Exemplary statements about financing offshore wind power development projects

Topic	Exemplary Quote	Expert Interviewee
Forms and sources of financing	*Only utilities can finance on balance sheet with large shares of equity – smaller players do not have this option.*	B1 (utility), Manager in Offshore Department
	We issue corporate bonds instead of using project finance. However, institutional equity investors are needed as well—they need to gain confidence in offshore wind!	J1 (independent developer), Technical Project Manager
Role of commercial banks	*Commercial banks are so risk averse right now that they do not assume any risks. They want guarantees for everything; the risks stay with the developers.*	G1 (municipality), Commercial Project Manager
	Project finance is very difficult to arrange for the construction phase: it requires consortium of many banks, it is relatively expensive […] and it takes away operational freedom from the developer. It is hardly impossible for the developer to establish favorable conditions.	C1 (utility), Manager in Offshore Department
	Individual banks do not take ticket larger than €75 million. Therefore, you need consortia with up to 15 banks to stem €1 billion debt finance—that is difficult to arrange.	H1 (municipality), Head of Offshore Department
Role of regulatory support	*The EIB plays a huge role for project finance! EIB offers interest rates under market price and is a real support for project finance. The KfW program helps to increase volumes but only replicates market conditions.*	G1 (municipality), Commercial Project Manager
	EIB and KfW programs are good as (time-limited) kick starters. However, it is essential that the financial markets heal again. There is not much policy makers can do about that.	K1 (independent developer), Head of Offshore Department
	Without help of the EIB the project finance deal would not have been possible!	H1 (municipality), Head of Offshore Department
Financing the investment gap	*The task ahead is gigantic – similar investment requirements in terms of magnitude and speed have rarely been seen in any other industry. Back of the envelope Europe needs €170 billion investment until 2020. Partnerships will be necessary.*	A1 (utility), Head of Offshore Department
	Until 2030 100 GW are planned in Europe, that is roughly 400 billion EUR investment or 20 billion EUR / year. This is too much for utilities alone, they do not have the financing capacity to do this. Thus, we need to bring in institutional investors.	J1 (independent developer), Technical Project Manager

Exemplary statements about grid access regulation for offshore wind power development projects

Topic	Exemplary Quote	Expert Interviewee
Grid connection regulation: UK vs. Germany	*In the UK the project management becomes easier with a more integrated approach to time management. However, there is additional burden for developer companies in terms of financing, complexity, and capabilities.*	G1 (municipality), Commercial Project Manager
	The UK regulation is better: less complexity and more control. The argument of inefficient connection redundancy does not hold: Developers will collaborate to align connections because it their intrinsic interest to save costs.	B1 (utility), Manager in Offshore Department
	Both regulation systems have their advantages and ironically, both regulators are thinking about implementing the alternative system: UK wants the "Steckdose auf See"; Germany wants to give responsibilities back to developers.	D1 (utility), Head of Offshore Department
Risks related to timing	*Position paper structures milestones and defines sequence of steps for grid connection; however, timing issue is still unresolved [...] TSO needs too much time and there is no binding law that allocates risks in case the connection is late.*	H1 (municipality), Head of Offshore Department
	The process could be sped up if TSO would start grid connection provision prior to sealing the turbine contract. A bank guarantee or a really high fee could provide credibility to development project. Yet, this could go beyond the financial might of small developers and put them at a disadvantage.	A1 (utility), Head of Offshore Department
Risks related to legal uncertainties	*Position paper goes into right direction as it aims to solve the chicken-egg-problem of the timing of the grid connection commitment – but it is not legally binding. This creates legal risks for the developers and the TSO.*	F1 (utility), Commercial Project Manager
	The position paper does cannot be legally enforced. No developer will build an OWP irrespective of missing grid connection and then sue the TSO – the risk is too high. Therefore a claim for indemnification is worthless if the 30 months limit cannot be upheld be the TSO.	A1 (utility), Head of Offshore Department
	In case of cable failure, there is an asymmetry of incentives and repercussions: the TSO needs to repair the damage but only the OWP owner has a financial downside from the damage. Banks and insurers require an extra premium due to this lack of control.	I1 (municipality), Commercial Project Manager
Role of TSO	*In the early planning phase it is helpful, especially for small developers, that the connection responsibility resides with the TSO. Later during specific planning and construction of the connection it is a big challenge for a single company with its limited resources like TenneT to ensure this national task.*	K1 (independent developer), Head of Offshore Department
	Very understandable: the TSO has limited capacity, so commitments to bind resources need to be sensible. The TSO has to be sure that developer will actually deliver.	M1 (SPV), Technical Project Manager
	The new position paper aimed to solve the timing conun-drum, but creates new uncertainties for the TSO as to how high the realization probability is after the final investment decision for the construction of the grid connection.	G1 (municipality), Commercial Project Manager

Exemplary statements about grid access regulations for offshore wind power development projects

Topic	Exemplary Quote	Expert Interviewee
Complexity and structure of administrative process	*We contacted 50 institutions and authorities; dealt with at least eight legal persons, and three different federal ministries. It is very complex; one project took 14 years!*	K1 (independent developer), Head of Offshore Department
	It is not always clear to us which authority has the lead in the process.	B1 (utility), Manager in Offshore Department
	Better coordination would be necessary. Responsibilities are sometimes not clear cut and even single entities do not have a coherent agenda.	F1 (utility), Commercial Project Manager
Definition of standards	*German authorities want German rules – there is stubbornness in simply adopting international regulatory standards. This takes a lot of time.*	L2 (independent developer), Manager in Offshore Department
	All authorities are still in the process of developing standards and clarifying new situations and quests. Organizational learning is important here, however hard to do with short term contracts and the resulting brain drain.	A1 (utility), Head of Offshore Department
	The execution risk is levered through regulatory imprecision. BSH standards need to be developed further. It is crucial to understand what the relevant milestones are and what is needed to fulfill them.	C1 (utility), Manager in Offshore Department
Attitude, collaboration and transparency	*The UK is a positive example of massive, continuous, and long-term oriented support for offshore wind power. They have a comprehensive approach where all forces are pulling on one string; all the way from central government down to the lowest responsible authority.*	K1 (independent developer), Head of Offshore Department
	UK is world market leader in offshore wind and want to keep that status. Regulators are engaging in discussions with developers and ask questions like: How can we abolish barriers? How can we make it happen?	D1 (utility), Head of Offshore Department
	The collaboration with the BSH is really excellent! The other authorities are more difficult to deal with.	I1 (municipality), Commercial Project Manager
Environmental regulation	*Noise protection is one of the biggest hurdles in Germany. It is not a topic in the UK, in fact, in no other country.*	G1 (municipality), Commercial Project Manager
	The BFN is in battle for competencies with the BSH. They have veto rights and can even put ex-post requirements on running development processes. Process security is key! Additional restrictions are killing our planning processes and put the entire investments at risk.	A1 (utility), Head of Offshore Department
	The UK is less aggressive in its stance on environmental regulations. They prefer real life tests, make an assessment of impact on environment and then react if necessary. Germany assures beforehand that there will not be detrimental repercussions of construction activities.	D1 (utility), Head of Offshore Department

Exemplary statements about legal security with respect to developing offshore wind power

Topic	Exemplary Quote	Expert Interviewee
Stability of primary support scheme	*Reliability is very important!! Recent changes of solar subsidy are annoying but not really disruptive to projects because of the short construction times of solar parks. However, a similar regulatory behavior with offshore wind would be very disastrous!*	C1 (utility), Manager in Offshore Department
	We consider the legal security of the EEG as very high and do not expect a fundamental worsening.	I1 (municipality), Commercial Project Manager
	UK plans fundamental changes to the primary support schemes, switching from the ROC scheme to FITs. But companies are not too worried. The UK government is very cautious, engaging and keeps stakeholders well-informed. Most changes seem to be improvements anyway.	E1 (utility), Manager in Offshore Department
Legal status of provisions, enforceability	*Arrangements often lack reliability. Authorities only give oral statements or meeting write-ups instead of official, written statements. This is triggered by uncertainty on their side of authorities because they do not want to run into trouble by making rules on the fly.*	L1 (independent developer), Manager in Offshore Department
	Legal security is obscured due to inadequate timing of milestones. The platform for example, is impossible to design and construct economically if we adhered to the BSH regulations and timing.	M1 (SPV), Technical Project Manager
Impact of unforeseen changes	*It is really bad for us when regulations are added or changed ex-post. But developers are already invested with money and people and are a bit at will of the authorities.*	D1 (utility), Head of Offshore Department
	There were unforeseen costs and requirements, even beyond what was learned at Alpha Ventus. This led to diminished economics of the project.	H1 (municipality), Head of Offshore Department

Chapter 4

Comparison of the Financial Attractiveness among Prospective Offshore Wind Parks in Selected European Countries

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Comparison of the financial attractiveness among prospective offshore wind parks in selected European countries

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ABSTRACT

Offshore wind power is regarded as a crucial renewable energy technology to achieve the ambitious CO_2 reduction targets of the EU. However, offshore wind power is not yet competitive with traditional electricity generation technologies, so its sustained development depends on national support policies.

Employing a DCF model, this paper scrutinizes how national regulations and geographic conditions of designated national offshore wind development areas affect profitability. The focus of the analysis is on a set of hypothetical offshore wind park scenarios from five countries (Belgium, Denmark, Germany, France, and the UK). The inclusion of geographic conditions is significant, since water depth and distance to shore influence costs and because available wind resources determine the amount of electricity produced.

The paper's findings are threefold: Firstly, profitability results indicate that currently relevant scenarios in the UK and Germany are most attractive, but that the upcoming UK Round III projects have low attractiveness. Belgium, France, and Denmark follow in the rankings successively. Secondly, there is high variation among scenarios with respect to capital costs—differences amount up to +61%. Lastly, a future scenario assuming technology improvements and learning effects suggests that remuneration levels could be lowered by ~25% by 2020.

1. Introduction

During the upcoming years the EU aims to achieve ambitious CO_2 reduction targets. With respect to the decarbonization of the existing energy systems, this requires a shift toward zero-carbon-emitting technologies. With nuclear power facing strong opposition in many European countries and Carbon Capture and Storage of fossil fuels struggling with technological and acceptance issues, a large share of future power generation capacity will have to come from renewable energy technologies (RETs). Thus, RETs are at the heart of the transition toward low carbon economies in Europe.

Among the various RETs that are employed today, offshore wind power plays a pivotal role in delivering a substantial share of the future RET capacity in Europe. The arguments supporting the substantial usage of offshore wind power include, among others, its enormous potential for electricity production[1]; favorable maritime conditions with comparably shallow waters and strong winds in the North Sea and the Baltic Sea (Jay, 2010); usage of ever larger turbines increasing economies of scale (Snyder and Kaiser, 2009), while potentially having less public opposition due to lower visual impact and turbine noise disturbance (Esteban et al., 2011; Haggett, 2008); and prospects of industry development, job creation and European technology leadership (Bilgili et al., 2011; EWEA, 2009c).

Hence, policy makers in Europe have set ambitious goals for the development of offshore wind power. Combining the numbers that the EU countries have set forward in their National Renewable Energy Action Plans (NREAPs) in 2010, roughly 42 GW will be installed until the year 2020 (European Commission, 2010b). This is in line with the European Wind Energy Association's estimation of 40 GW European offshore wind power capacity in 2020 in their optimistic "policy impetus" scenario (EWEA, 2007). These targets would require a more than tenfold increase from the currently installed capacity of around 3.3 GW at the end of the first half of 2011 (EWEA, 2011a). The most ambitious development goals exist in the UK and Germany, where the installation of 13 GW

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[1] According to a study by the EEA (2009) the theoretical technical offshore wind power potential in European waters amounts to 3500 TWh in 2030. Theoretically, this could be enough electricity to supply around three quarters of Europe's predicted electricity consumption in 2030. These numbers already include spatial considerations for competing maritime usages such as shipping, tourism, oil and gas exploration, environmental protection, and military.

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Table 1
Ernst and Young (2011) "Renewable energy country attractiveness indices"—Offshore Wind Index.

Country	Score
1. United Kingdom	77
2. Germany	77
3. China	70
4. Belgium	58
5. USA	56
6. Denmark	56
7. France	55
8. Sweden	53
9. Netherlands	53
10. Ireland	52

Table 2
KPMG (2010) market survey ranking of offshore wind markets by expected returns.

Country	Assessment
1. United Kingdom	Very attractive
2. Germany	
3. Belgium	
4. Netherlands	
5. Spain	
6. Ireland	
7. Denmark	
8. France	
9. Sweden	Least attractive

and 10 GW offshore wind power capacity respectively are planned until 2020 (European Commission, 2010b).

However, being a young industry, offshore wind power has not yet reached market competitiveness and still faces economic, technical, and regulatory challenges (Markard and Petersen, 2009; Toke, 2010). To overcome these barriers, national governments have implemented different types of subsidy schemes, such as feed-in-tariffs (FITs), tradable certificates, or tender schemes, to foster the development of offshore wind power. The resulting levels of remuneration that operators of offshore wind parks (OWPs) receive for their electricity, expressed in ct/kWh, can serve as a first indicator for the attractiveness of the offshore wind power market in different European countries. However, this remuneration-focused perspective would fall short in assessing the real financial attractiveness of the different offshore wind markets.

The quarterly "Renewable Energy Country Attractiveness Index" by Ernst and Young (2011) adopts a more comprehensive approach to assessing a country's attractiveness for offshore wind. It incorporates multiple parameters covering the general regulatory setting for renewable energy as well as offshore wind specific technology factors. Yet from a scientific perspective, the choice of parameters as well as their relative weighting seems arbitrary and the resulting index values[2] (see Table 1) do not offer a profitability indication for OWPs in the respective countries.

A recent KPMG industry report (KPMG, 2010) advances the financial evaluation further using a profitability indicator to determine the attractiveness of the offshore wind markets in different European countries. It attempts to assess the financial attractiveness of offshore wind development by employing a survey among industry participants, asking for the offshore wind markets with the highest "expected returns" (see Table 2).

Since the ranking is based on expert opinions only and results reflect perceived preferences rather than a fact-based analysis, its objectiveness is rather limited. Thus, a more systematical and transparent analysis is needed to generate a thorough understanding of the financial attractiveness and its drivers of the offshore wind markets in different European countries.

This paper strives to contribute to the existing literature by conducting a comprehensive assessment of the financial attractiveness of the major offshore wind power markets in Europe. The key instrument for this assessment is an economic analysis of hypothetical OWPs for a set of scenarios. Employing a discounted cash-flow (DCF) model, the dependent variable and basis of comparison will be the OWPs' internal rate of return (IRR). In this the IRR will be used as proxy for financial attractiveness as perceived by investors. Input parameters for the DCF model are differences in costs structures, resulting from varying water depths and distances to shore, different grid connection regulations, as well as differences in revenue levels due to varying electricity-generating potential and respective national subsidy regimes. The chosen approach is novel in two ways: First, it explicitly includes the impact of geographic parameters. Second, the high granularity, reflected in multiple scenarios per country, allows for an intra-country comparison of financial attractiveness. Thereby, the paper aims not only to create transparency of the financial attractiveness of the offshore wind markets in different European countries in general, but also to highlight how regulatory choices affect the profitability of OWPs from an investor's perspective.

The remainder of the paper will be structured as follows. Section 2 gives an explanation of the methodology employed for both the country selection and the economic analysis. Section 3 continues with a detailed description of the rationale for the underlying data assumptions. Section 4 then discusses the resulting profitability performance indicators for the set of hypothetical OWPs from the country sample and other results. Finally, conclusions of the findings are synthesized and limitations of the research approach are discussed in the last section.

2. Methodology

The focus of the paper is the comparison of the financial attractiveness of hypothetical OWPs from different development areas in Europe. Table 3 shows the NREAPs that member states submitted in 2010. Out of the 27 EU member states, 8 countries project offshore wind power capacities of more than 1 GW by 2020. These are Belgium, Denmark, France, Germany, Netherlands, Spain, Sweden, and the UK. The other countries do not expect significant offshore capacity installations until 2020 and are therefore excluded from the economic analysis.

Of the eight countries with large planned capacity additions the Netherlands, Sweden, and Spain are not considered in the analysis. In the Netherlands, the terms and conditions of the support scheme are not publically available. Sweden does have a well-defined and transparent support scheme. However, since compensation levels are low, several development projects were put on hold and construction is delayed pending further notice. The status of the project pipeline is unclear and thus no information on OWP locations is available to specify the modeling of the cost structure. Spain has not yet officially approved OWP development areas and hence must also be excluded from the analysis.

The financial attractiveness of the hypothetical OWPs from the final country sample, consisting of Belgium, Denmark, France, Germany, and the UK, is assessed by means of an economic analysis that covers both costs and benefits. On the cost side,

[2] Index values are scored out of 100. Offshore specific technology factors weigh 65%, and the assessment by country of the general regulatory infrastructure for renewable energy accounts for the rest.

Table 3
Present and projected offshore wind capacities in EU-27.
Sources: EWEA (2009a), (2011a), (2011b); National Renewable Energy Action Plans (European Commission, 2010b)

Country	2011 capacity as of Q2 (MW)	2020 national plan (GW)	EWEA 2020 (GW)	
			Low	high
UK	1586	13.0	13.0	20.0
Germany	195	10.0	8.0	10.0
France	0	6.0	4.0	6.0
Netherlands	247	5.2	4.5	6.0
Spain	0	3.0	1.0	1.5
Sweden	164	1.8	3.0	3.0
Belgium	195	*1.8*	1.8	2.0
Denmark	854	1.3	2.3	2.5
Italy	0	0.7	0.5	1.0
Ireland	25	0.6	1.0	1.0
Poland	0	0.5	0.5	0.5
Greece	0	0.3	0	0.2
Others	28	1.0	0.4	1.3
EU-27	**3294**	**45.2**	**40.0**	**55.0**

there are three major cost buckets: (a) initial capital costs to plan and construct the wind farm; (b) annually occurring variable costs, which mainly arise from operation and maintenance (O&M) activities; and (c) dismantling costs arising at the end of lifetime. In contrast, there are yearly revenues that depend on the amount of electricity generated and its achievable or guaranteed selling price. The final indicator used for the comparison of financial attractiveness between different OWPs is profitability. Fig. 1 depicts the key profitability drivers of an OWP once again.

For the calculation of the profitability of the national OWP scenarios, a standard DCF model is applied. The model discounts the cash flows – costs and revenues – spread over the lifetime of an OWP to a base year. The DCF approach generally allows for calculating of two different types of profitability parameters: net present value (NPV) parameters based on a given discount rate and the IRR—the internal profitability rate of a project. Formally, the IRR is derived by calculating the discount rate that sets the NPV to zero:

$$NPV = \sum_{n=0}^{N} \frac{C_n}{(1+r)^n} = 0$$

where r is the discount rate; n is a given year, N is the total number of years, and C is the cash flow in a specific year. For the purpose of the comparison exercise in this paper, the IRR is an adequate and objective profitability indicator. First it does not require assumptions on discount rates (Brealey et al., 2010).[3] Second, it incorporates both costs, mainly influenced by the geographic conditions, and revenues, influenced by the national compensation schemes as well as the wind resource. Thus, it well reflects the specific characteristics of the national OWP scenarios.

Note that the economic analysis is based on nominal values; i.e., it does not include inflation effects but bases all calculations on fixed 2010 prices.[4] Furthermore, the economic analysis is conducted on a simple national economic basis. This modeling approach deliberately excludes taxes, depreciation effects, or financing structures to facilitate robust comparability of the fundamental, scenario-specific profitability drivers.[5] The excluded parameters depend on company-specific factors, which would dilute comparability. Companies have certain degrees of freedom with respect to the application of accounting, depreciation and evaluation methods, influencing the taxable income. Companies also differ in their financing abilities, which also affects the taxable income. Finally, national or regional tax laws do not treat companies equal, as reduced taxes may serve as subsidies to attract business in specific areas.

3. Wind energy economics and resulting model assumptions

After having outlined the methodology, this section focuses on the assumptions, which serve as input for the economic analysis.

To ensure comparability, the set-up of the hypothetical OWP is identical for all scenarios, independent of the country or location. It has a size of 400 MW, corresponding to 80 turbines of 5 MW.[6] The construction of the OWP takes 2 years, but 50% of the total capacity is already available in the first year, and the rest within year 2. Furthermore, the model assumes the turbine's lifetime to be 20 years,[7] so the total time period under review is 21 years.

Further key assumptions can be categorized into three major groups: (a) revenue assumptions, (b) cost assumptions, and (c) national scenario selection. Instead of solely presenting the chosen assumptions, the paper provides a perspective on how the different assumptions interact in the model as well as some selected historical developments of these assumptions.

3.1. Revenue assumptions

Revenues of an OWP are a function of the attainable remuneration per unit of electricity produced and the amount of produced electricity subject to the available wind resource. With regard to remuneration, national support policies are the decisive element, as offshore wind power generation is still too expensive to compete against conventional energy production. Table 4 provides an overview of the primary support mechanisms for offshore wind power in the country sample, the respective levels of remuneration under current national legislations, and the corresponding assumptions for the DCF model.

The main support mechanisms employed are FITs, tradable certificates, and tender schemes. FITs – as used in Germany – set a fixed price for every unit of produced energy, which operators obtain for a predefined period.[8] In contrast, the systems in Belgium and the UK require electricity suppliers to prove that their energy mix contains a predefined share of renewable energy based on green certificates. The interaction of supply and demand then determines the green certificate price. Additionally, OWP operators in these countries receive the market price for the sold electricity. Finally, the Danish and French tender systems require OWP operators to bid for the right to develop a new project. The permission is assigned to the most competitive

[3] The alternative NPV-based profitability indicators, such as return on investment or return on equity, require an assumption on the discount rate. Results are highly sensitive to the choice of this discount rate, especially for long-term and capital intensive projects such as offshore wind power farms.

[4] The time value of money is still accounted for as future cash flows are discounted with the IRR.

[5] The resulting profitability number is comparable to an EBITDA perspective.

[6] This uniform set-up results in a bias, slightly disfavoring future OWPs with a size larger than 400 MW, e.g., projects of the UK—Round III scenario. These OWPs potentially benefit from economies of scale with respect to laying the electric export cable and in the procurement of turbines. However, the total effect is not exorbitant, as most cost elements are not affected by the size of an OWP.

[7] KPMG (2010), EWEA (2009b), and Junginger (2005) use the same assumption for a turbine's lifetime in their calculations.

[8] The predefined period in Germany is 8 years plus a possible extension for geographic conditions: +1.7 months for every meter beyond a water depth of 20 m and +0.5 months for every nautical mile beyond a distance to shore of 12 nautical miles.

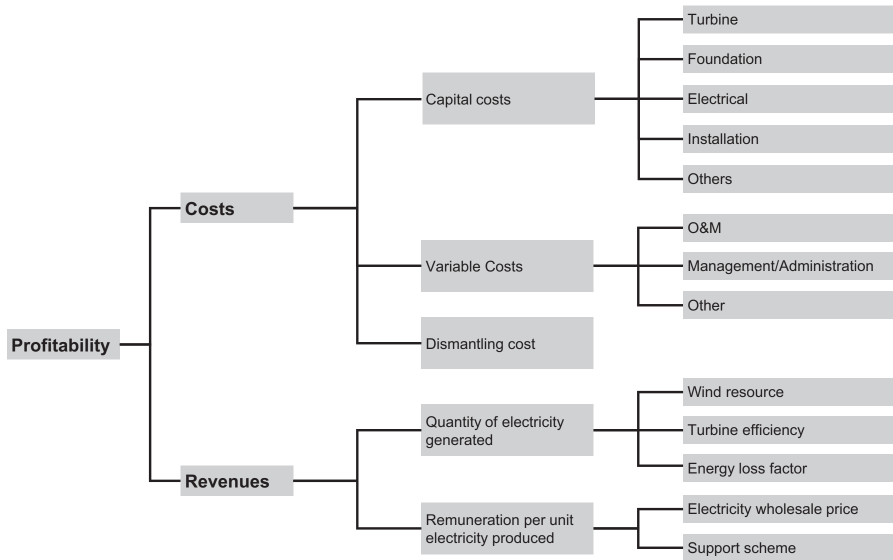

Fig. 1. Key profitability drivers of OWP.

Table 4
Support policies for offshore wind power in selected European countries.
Source: Own analysis of national legislations, KPMG (2010), Green and Vasilakos (2011), national electricity exchanges.[a]

Country	Primary support mechanism	Level of remuneration	Duration	Assumption in model
Belgium	Tradable green certificates	Electricity market price plus one green certificate (guaranteed minimum of 10.7 ct/kWh for first 216 MW of each OWP; 9 ct/kWh for each additional MW)	20 years	Electricity price: ~ 4.9 ct/kWh Total: 15.6 ct/kWh for first 216 MW 13.9 ct/kWh for each additional MW
Denmark	Tender system/Feed-in tariff	FIT according to project specific tender Anholt: 14 ct/kWh	According to project specific tender Anholt: 20 TWh	14.0 ct/kWh for first 20 TWh, thereafter electricity price: 5.2 ct/kWh
France	Tender system/Feed-in tariff	FIT corridors provided in invitation to tender: *1 corridor (Channel):* 11.5–17.5 ct/kWh *2 corridor (Atlantic):* 14.0–20.0 ct/kWh	20 years	*1 corridor (Channel):* 14.5 ct/kWh *2 corridor (Atlantic):* 17.0 ct/kWh
Germany	Feed-in tariff	*Phase 1*: 19 ct/kWh; 15 ct/kWh for extended months *Phase 2*: 3.5 ct/kWh	*Phase 1:* 8 years plus possible extension *Phase 2:* after Phase 1 until end of year 20	*Phase 1*: 19.0 ct/kWh; 15 ct/kWh for extended months *Phase 2:* electricity price: 5.1 ct/kWh
UK	Tradable green certificates	Electricity market price plus 2 renewable obligation certificates (ROCs)	20 years	Electricity price: ~ 5.5 ct/kWh ROC: ~6.1 ct/kWh Total: 17.7 ct/kWh

[a] Electricity prices based on annual average base prices from the respective national electricity exchanges: Germany: EEX, Oct 2010—Oct 2011; Denmark: Nordpool, 2010; Belgium: BELPEX, year to date 2011; UK: APX, July 2010—July 2011.

bid—determined either by a scoring system[9] or the lowest proposed FIT.[10]

In the third column, Table 4 provides the conditions and the level of remuneration that owners of OWPs receive per kilowatt hour of electricity produced. Following the industry's call for higher support levels, the UK government increased the compensation for offshore electricity from 1.5 ROCs to 2.0 ROCs in 2009 (for more information compare Toke (2010)). Similarly, German offshore associations pushed for higher compensation levels (OFW et al., 2010), and the so-called "Stauchungsmodell"[11] was implemented in the renewable energy law in July 2011.[12] Though the new regulation will only be valid as of January 2012, the parameters of the Stauchungsmodell serve as model assumptions for Germany. The latest tender in Denmark, which has been concluded in 2010 at a level of around 14 ct/kWh, also asserts the trend of increasing support levels (Danish Energy Agency,

[9] A scoring system usually includes additional aspects such as job creation or environmental impact.

[10] For a more detailed explanation of the functionalities of the various primary support mechanisms and how they are currently implemented, please see the description provided by Green and Vasilakos (2011).

[11] English: "compression model"; term indicating that the period of subsidized FIT has been shortened.

[12] The Stauchungsmodell intends to improve both risks and project returns by preponing revenue streams to earlier years while leaving the total sum of subsidies identical (in nominal terms) to the previous regulation. According to KPMG (2010) which assumes a slightly different compression modus (20 ct for 9 years, instead 19 ct for 8 years), improvements in profit margin could be as much as +3 percentage points.

2010). The single country without adjustments to its support scheme is Belgium, where OWP operators receive the guaranteed minimum price for green certificates.

France is a special case as the conditions for power remuneration were still subject to an ongoing tender process at the time of writing.[13] The tender documents propose two price corridors for potential remuneration levels that correspond to geographic location (French Ministry of Ecology, Sustainable Development, Transport and Housing, 2011). In the economic analysis, the midpoints of these corridors are assumed.

For Denmark, France, and Germany model assumptions correspond directly with the FIT levels set by the respective national laws. After the FIT period is over, OWP operators in Denmark and Germany will sell their electricity to the competitive power market.[14] In contrast, remuneration levels in Belgium and the UK always depend on fluctuating market prices for both electricity and tradable certificates. Nevertheless, the assumed total compensation of 17.7 ct/kWh for the UK and the two assumptions for Belgium are treated as being constant over the entire period to reflect nominal prices.

The second major variable influencing the revenue of an OWP is the produced electricity. The three factors determining the producible amount of power are mean wind speeds, gross full load hours, and the energy loss factor.

Maritime wind speeds tend to be both higher and more stable than onshore wind speeds, leading to a more steady wind power production, as a significant part of the time, the turbine produces at full load. Nevertheless, the variation between strong and weak wind years can still be significant. To account for this factor, the model uses information from 4C offshore,[15] which applies a ten-year mean wind speed from the period January 2000 to December 2009. The 4C offshore data set is based on NASA satellite data measuring wind speeds at 10 m height[16] and additionally transforms the NASA data to reflect wind speeds at a hub height of 100 m (4C Offshore, 2011a). Hence, the data set gives an unbiased estimate of the wind resource for each real OWP used as input for the model (compare Appendix A for the granular data). In a second step, these individual values are averaged to obtain a representative mean wind speed for each scenario of the economic model.

To arrive at gross full load hours,[17] a transformation approach developed by M. Hoogwijk for EEA (2009) is applied. The chosen approach uses power–velocity curves and the Weibull distribution to convert mean wind speeds into gross full load hours.[18] This procedure is a reliable approximation of the theoretical full load hours, which was also used by the EEA to evaluate the European offshore wind potential.

Gross full load hours are only the ideal upper limit of the power production potential. To calculate the real running time of a wind turbine, it is necessary to adjust for downtime and array losses (EWEA, 2009b). Downtime arises from machine failure, repair and maintenance, and shut offs during storms. Array losses result from interferences of turbines within an OWP. All of these effects are combined in an energy loss factor. Similar to EWEA (2009b), an adjustment for energy losses of 14% is assumed for the economic model, which is in line with the 10–15% stated in Blanco (2009). The multiplication of gross full load hours and energy loss factor yields the net full load hours. The latter is the final number used to calculate the annual electricity production of a hypothetical OWP scenario:

$$\text{Annual electricity produced(MWh}/y) = \underbrace{(626.51 \times \text{Annual mean wind speed(m/s)} - 1901) \times (1-0.14)}_{\text{Net full load hours}(h/y)} \times \underbrace{400\,\text{MW}}_{\text{Installed capacity}}$$

Together with the above-presented remuneration schemes, these two numbers determine the revenue stream of an OWP scenario in the DCF model.

3.2. Cost assumptions

This section describes the three cost buckets of OWPs in detail and derives the respective assumptions that serve as input for the economic analysis.

3.2.1. Capital costs

The following cost breakdown of capital costs into different technical components and the installation of the offshore wind turbine can only provide a snapshot in time. It will differ significantly not only with local geographic conditions and technical design, but also with prevailing market conditions.

Capital costs of offshore wind projects can be divided into five categories (Junginger, 2005; EEA, 2009):

- Turbine—the turbine itself, blades and hub, tower, and all electrical components, but no installation or transportation cost.
- Foundation—manufacture of the foundation, but no installation or transportation cost.
- Electrical—inner park cabling, export cable linking the OWP to the shore, and offshore substation with foundations, but no installation cost.
- Installation—transportation of components, installation of turbine, foundation, and electrical components.
- Others—a variety of administrative and project-related tasks, such as environmental assessments, engineering studies, project management, and legal advice.

Typically, capital costs are standardized to the base of MW or kW. Analyzing the trend in capital expenditure (CAPEX), RenewableUK (2011) and Levitt et al. (2011), come to the conclusion that it substantially increased over the last years. Looking at quoted investment costs in the literature over previous years supports this finding. Junginger (2005) identifies turnkey investment costs for offshore wind farms in the range of 1.200–1.850 EUR per kW. EWEA (2009b) states a cost range of 2.0–2.2 mio EUR per MW. KPMG (2010) assumes average investment cost of approximately 3.300 EUR per kW when subtracting the contingency reserve of 10%. Similar MacDonald (2010) identifies medium total capital costs of 2.840 GPB per kW. The latest report available (RenewableUK, 2011) states a CAPEX of close to 3.0 mio GBP per MW.

[13] The first round of tenders for 3 GW offshore wind capacity will be decided upon in April 2012.

[14] This assumption supposes that OWP operators in Germany will be able to generate higher revenues during Phase 2 via direct power marketing than the minimum level of 3.5 ct/kWh.

[15] Commercial company specialized on providing information on OWPs.

[16] According to 4C Offshore (2011b) the wind speed data is derived from *"high resolution satellite data* (0.25°) *which has been obtained from up to* 6 *satellites operated by NASA, and has undergone internal and external validation against offshore buoy measurements and two offshore wind meteorological masts"*.

[17] Gross full load hours indicate the amount of time per year that a given turbine produces power at full name plate capacity (kWh/y)/(kW).

[18] The precise formula for the transformation of offshore wind speeds is: Gross full load hours/year = 626.51 × mean wind speed (in m/s)—1901. Since the same transformation is applied for all OWPs, there is a small bias. Locations with low mean wind speeds and consequently smaller optimal turbine size are favored, whereas locations with high mean wind speeds, allowing for larger turbines, are disfavored.

Table 5
Overview of investment cost split for offshore wind farms in the literature.

	RenewableUK (2011) (%)	EWEA (2009b) (%)	EEA (2009)[a] (%)	Junginger (2005) (%)	**Model assumption** (%)
Turbine	40	49	43	30–50	39
Foundation	19	21	20	15–25	21
Electrical	14	21	7	15–30	11
Installation	23		26	0–30	25
Other	4	10	9	8	4

[a] The cost split refers to the EEA (2009) base scenario of 1800 EUR per kW.

This result seems counterintuitive at first, since learning curves and economies of scale should drive down investment costs. However, there are several economic and market conditions that explain the increase in investment costs (Levitt et al., 2011). First, changes in macroeconomic factors such as prices of raw material and labor cost; second, growing demand for and limited supply of offshore wind equipment, such as turbines or vessels; and third, increased understanding for the challenges to develop OWPs.

Consequently, the assumption with respect to total capital costs reflects the latest price developments in the offshore wind industry. With 3.800 EUR per kW for aggregated capital costs, it is at the upper end of the presented cost ranges. However, considering adjustments for geographic conditions and grid regulation as discussed later, this assumption is well in line with the latest available data sets presented in RenewableUK (2011) and KPMG (2010).[19]

The split of total investment costs into single cost categories is also discussed with a certain variation in the literature. Table 5 provides an overview of investment cost splits presented in the literature and of an exemplary model assumption.[20]

The category with the highest cost share in all reports – close to 40% and above – is *Turbine costs*, followed by *Installation costs* – around 25% – and *Foundation costs*—around 20%. *Electrical costs* show the greatest variation among reports, ranging from 7% to 21%, whereas the share of *Other costs* is not greater than 10% in any report. The discrepancy between reports is to a great degree explainable by the variation of assumptions with respect to the geographic conditions. Both the EEA (2009) base case and EWEA (2009b) analyze OWPs that are close to the coast and in shallow waters.

As mentioned above, capital costs as well as the relative proportion of the cost components are not static, but depend heavily on geographic conditions. The two major factors that are identified in the literature as having an influence on investment costs are water depth and distance to shore (Bilgili et al., 2011; Green and Vasilakos, 2011). The recent cost assessments of RenewableUK (2011) and KPMG (2010) also mention these two influencing factors, but do not quantify them. EEA (2009) provides a good quantitative assessment for the influence of the water depth and distance to shore. Appendix B1 shows the original data from this report in white; gray cells indicate linear adjustments to provide a greater degree of granularity. Obviously, cost levels used in EEA (2009) are too low compared to current standards. To calibrate to scaling factors that match actual cost levels, ratios between the single elements are retained, but a new starting value is defined. This starting value assumes a water depth of 30 m and a distance to shore of 40 km. Furthermore, the corresponding investment costs reflect the previous assumption of 3.800 EUR per kW. The resulting scaling factor table is presented in Appendix B2.

The increase in distance from shore mainly affects the cost for the electrical system and the installation (Bilgili et al., 2011). The driving factor for the rising cost in the electrical system is the increased length of the export cable. With respect to rising installation costs, the biggest share is also assignable to the electrical related element; greater distances increase traveling costs and the risk of costly construction delays due to a higher dependency on suitable weather windows (EEA, 2009). The assumption for the distance-related change of installation costs[21] reflects this logic, as it allocates 80% of the change to the electrical installation and 10% to turbine and foundation installation each.

The move to deeper waters mainly influences the cost of the foundation as more robust monopiles or even other foundation technologies such as tripods, jackets, or floating structures are required (Bilgili et al., 2011). In addition, there is an increase in installation cost, as more sophisticated vessels are needed to install foundations in greater water depth (EEA, 2009). The assumption for the water-depth-related change of installation costs matches this correlation by allocating 80% of the change to the foundation installation and 10% to turbine and electrical installation each.

Applying the equal split of initial installation costs and the presented percentages for the geographic impact leads to the values and scaling factors for the installation cost subcategories displayed in Appendices B1 and B2.

Finally, there is variety of regulations with respect to the grid connection that influence investment costs attributable to the OWP operator (Weißensteiner et al., 2011). Depending on the regulatory setting, the OWP operator or the transmission system operator (TSO) may be in charge of providing the grid connection. Hence, in case the OWP operator is in charge, costs of the electrical hardware and the corresponding electrical installation costs are allocated to the investment costs of an OWP, whereas in the case of the TSO being responsible, they are excluded from investment costs and socialized over all electricity consumers. Thereby, energy policy makers have a direct impact on the capital costs of an OWP. In the country sample, the regulation in Germany and Denmark allocates the responsibility for the grid connection to the TSO, whereas the regulatory setting in France and the UK[22] puts OWP operators in charge of the grid connection (Weißensteiner et al., 2011). In Belgium costs are split between OWP operator and TSO. The former bears 2/3 of the grid connection costs, while the latter covers the remaining third, but only to a limit of 25 mio EUR (European Commission, 2010a).

Note that, independent of the regulatory setting, a certain portion of electrical costs that is related to inner-park cabling and

[19] KPMG (2010) states a water depth close to 30 m and a distance from shore of 40 km. Furthermore, grid connection costs are not included, as the German regulation puts the responsibility for the grid connection on the grid operator. Adjusting for these factors, the assumption results in total investment cost of around 3.300 EUR per KW; matching KPMG's average investment costs for the assessment of the German "Stauchungsmodel".

[20] Since the economic model used in this paper allows for adjusting investment costs according to geographic conditions, the model cost split is not fixed but varies depending on water depth and distance to shore (compare Fig. 2 in Section 4.1). The presented model assumptions reflect a setting with similar conditions as in the renewableUK report: water depth of 20 m and distance to shore of 35 km.

[21] The available reports do not provide a breakdown of the *Installation costs* into the single subcategories—turbine, foundation, and electrical installation costs. The DCF model assumes an even split of initial installation costs. Conducting sensitivity analyses with respect to this assumption reveals that the impact of different settings is neglectable (the impact on final results is around 10% in relative terms) as long as none of the three subcategories accounts for less than 20% of initial installation costs.

[22] Recent regulation in the UK requires the wind farm and the electrical transmission system to be separated. As a consequence OWP operators actually pay the cost for the grid connection in form of transmission charges. In order to keep the conventional split between CAPEX and variable costs, the paper allocates these costs, however, to investments costs, as it is done in RenewableUK (2011).

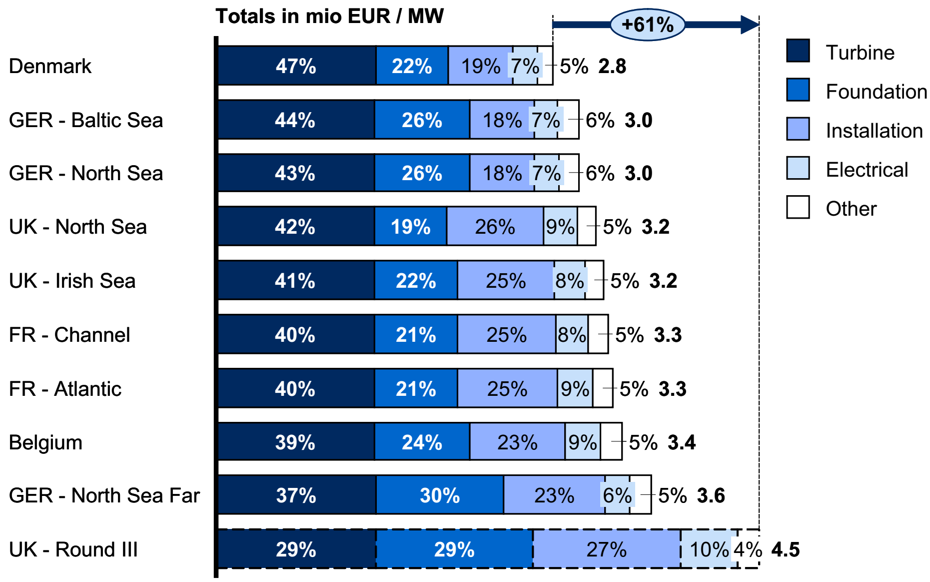

Fig. 2. Capital costs split across scenarios.

transformer stations is always attributable to the investment costs of an OWP. Supposing that the share of electrical costs, which is independent of the distance to shore in EEA (2009), reflects costs for transformer stations as well as inner wind farm grid and then adjusting this share to match the increased investment costs, a cost of 200 EUR per kW (~5% of total investment costs) is assumed for this cost bucket. This is in line with the 4% of total investment costs that Junginger (2005) identifies for the internal grid of an OWP as well as with the sum of the substation cost of 64.000 GBP per MW identified by (DTI, 2007) and the cost for the internal grid of 110.000 EUR per MW stated by EWEA (2009b).

In summary, both investment costs and its categories are not static but influenced by the geographic conditions of the OWP. Furthermore, the regulation of the grid connection is an influencing factor, since it defines the share of electrical and electrical installation costs that OWP operators have to bear.

3.2.2. *Variable costs*

Compared to fossil fuel-powered electricity generation, offshore wind has lower variable cost, since no primary fuel costs occur. Nevertheless, variable costs still account for a significant share of the total cost over the lifetime of a wind turbine; up to 30% according to Blanco (2009).

The elements included in variable costs vary between the different studies and reports, as there are significant variations between countries, regions and sites (Blanco, 2009). The most important element is O&M, including elements such as provision for repair and spare parts or proactive and reactive maintenance. Furthermore, management and administration is an element named in many reports. Other major categories are fees and insurance as well as rental for control buildings.

Cost estimates for the single elements are often subject to uncertainty, as offshore wind power is a young technology. Reliable long-term track records of variable costs are not yet publically available and published estimates range widely (Levitt et al., 2011). Also, the dominant O&M concept has yet to emerge. Different approaches such as joint ventures between different OWP operators, so-called "floatels," and even artificial offshore islands are being discussed.

Hence, variable costs of offshore wind are usually not calculated bottom-up (i.e., summing up the cost for the single elements outlined above), but rather top-down, reflecting a certain percentage of the initial investment costs or cost per MWh. According to a study by the German Wind Energy Association (Neumann et al., 2002) and also some newer reports (KPMG, 2010; EEA, 2009; EWEA, 2009b), variable costs are lower during the first 2 years of a turbine's lifetime, since in this period the turbine is usually covered by the manufacturer's warranty. The variable costs for the remaining years are estimated between 3% of total investment cost (RenewableUK, 2011; KPMG, 2010; MacDonald, 2010): and 5% in EWEA (2009b), which discusses several older studies. The cost estimates of 4% by the EEA (2009) and Junginger (2005) lie in the middle of this range.

The assumptions of variable costs for the DCF model reflect the logic of two distinct rates, using 2.5% of total investment cost for the first 2 years and 4% for the remaining lifetime.

3.2.3. *Dismantling costs*

Lastly, a wind turbine needs to be dismantled at the end of its lifetime. There is little information on dismantling costs as they are absent in many reports. The few reports in which dismantling costs are quantified range from assuming no dismantling costs at all because the residual value of the wind turbine will compensate for the dismantling cost (renewableUK, 2011) to 0.2 mio EUR per MW (KPMG, 2010). The latter value is assumed for the economic analysis.

3.3. *Selection of national scenarios*

In order to compare the attractiveness of hypothetical OWPs within the country sample, ten scenarios are defined, with multiple scenarios for the most dynamic offshore wind power markets – the UK and Germany. The defined scenarios differ in respective national support regimes as well as geographic conditions, such as water depths, distances to shore, and wind speeds (see Table 6).

Each scenario represents a set of development areas with similar geographic conditions that are designated for the construction of OWPs; UK—Round III is an exception in this

Table 6
Overview of scenarios used in the economic analysis.

Scenario name	Description	Ø water depth (m)	Ø distance to shore (km)	Ø wind speed (m/s)
Belgium	Belgian development areas	35	25	10.2
Denmark	Danish development areas	20	15	8.8
FR—Channel	French development areas in the Channel included in the current tender process	15	20	9.4
FR—Atlantic	French development areas in the Atlantic included in the current tender process	20	20	8.9
GER—Baltic Sea	German development areas in Baltic Sea	25	25	8.8
GER—North Sea	German development areas in North Sea <70 km distance from shore	35	25	9.9
GER—North Sea Far	German development areas in North Sea ≥ 70 km distance from shore	85	35	10.2
UK—Round III	British development areas in designated Round III territories and Scottish territories	60	40	9.9
UK—Irish Sea	British development areas in Irish Sea Round I & II territories	10	20	9.8
UK—North Sea	British development areas in North Sea Round I & II territories	15	15	9.6

perspective as it covers a mixture of locations. The data of a total of 72 real OWP development areas have been gathered to derive the assumed average water depths, distances to shore, and wind speeds of the respective scenarios.[23] Primary data sources are the respective official national institutions; missing information is filled with data from private organizations' or companies' databases covering OWPs from several countries. The selection of OWPs is limited to parks that have been put into operation recently or parks that have a valid building permit. The exception to this approach is the scenario *UK—Round III*, which consists of OWPs that have not yet received a planning consent.[24] To reflect this methodological difference, *UK—Round III* is highlighted with a dashed line and lighter shading in the following analysis sections.

The DCF model uses the framed cost and revenue assumptions to calculate the IRR of hypothetical OWPs with the described standard setup, for which the 10 presented scenarios set the different boundary conditions. The following section discusses the results of this calculation exercise.

4. Discussion of results

The results of the economic analysis allow for comparison between the various scenarios with respect to cost structures, full load hours and profitability values. Furthermore, a sensitivity analysis scrutinizes the impact of changes in some key parameters and a future scenario provides a perspective on how future developments may change the competitive landscape. Note that all displayed values reflect model values for the given set of assumptions rather than real project data. However, the strength of the analysis at hand is the ability to draw unbiased comparisons between scenarios.

4.1. Comparison of cost structures

Fig. 2 shows total investment costs as well as individual cost components for all 10 scenarios.

Total investment costs vary significantly across scenarios—the most expensive scenario requires investment costs of +61% compared to the least expensive. *Denmark*, *GER—Baltic Sea* and *GER—North Sea* have the lowest costs levels – around 3 mio EUR/MW – because in these countries grid connection costs accrue to the TSO. Development areas with little distance to shore and shallow waters but with (partial) responsibility for the grid connection, like in Belgium, France, and some parts of the UK, rank in the middle of the cost range—with investment costs of around 3.3 mio EUR/MW. In contrast, development areas that are far off the coast and in deep waters, such as *GER—North Sea Far* and *UK—Round III*, have to cope with even higher investment costs – totaling up to 3.6 mio EUR/MW or even 4.5 mio EUR/MW respectively. The data for the *UK—Round III* scenario highlights the large sum of grid connection and electrical installation costs – close to 1 mio EUR/MW for this scenario – that OWP operators may have to bear in the UK. If OWP operators in Germany were responsible for the grid connection costs, investment costs of *GER—North Sea Far* would be higher as in the *UK—Round III* scenario.

Fig. 2 also provides a perspective on the respective cost elements. The cost share of turbines decreases continually with increasing total costs, ranging from 47% down to 29%. Cost shares attributable to foundation and installation vary significantly across scenarios, ranging from around 20% to 30%. This is mainly the consequence of differing water depth and distance to shore. Additionally, the cost bucket installation also depends on the regulation of the grid connection, which defines whether or not the cost of the export cable installation accrues to the TSO or the OWP operator. Together with distance to shore, the grid regulation is also the biggest driver of the share for electrical costs, which ranges from 6% to 10%. There is hardly any difference between the scenarios with respect to other investment costs.[25]

The above results emphasize that water depth, distance to shore, and grid regulation are of paramount importance for offshore wind power construction. This leads to two conclusions. First, it underlines that national regulation influences more than just the revenue streams of OWPs. Second, it becomes evident, that for offshore wind power investment, cost indicators such as mio EUR/MW are only meaningful in association with the assumed geographic parameters and grid regulation. This notion should be taken up more consequently in the literature dealing with offshore investment costs. As more and more empirical data on offshore wind power costs are gathered, scientists should

[23] Please refer to Appendix A to see the full list of OWP and development areas that compose the scenarios.

[24] There are two reasons for including the *UK—Round III* scenario albeit the difference in planning stage. First, it is very important for the future development of offshore wind in Europe due to its sheer size. Second, it is structurally different in that it largely represents new territories and will therefore face different economic challenges than the other UK scenarios. Note, that the difference in planning stage can potentially result in small bias disfavoring *UK—Round III*, as some unfavorable OWP development areas are included, although they may never materialize.

[25] As variable costs are modeled as a share of total investment costs, they behave similarly and are not shown separately. Note that this increases the discrepancy of lifetime costs among the scenarios further.

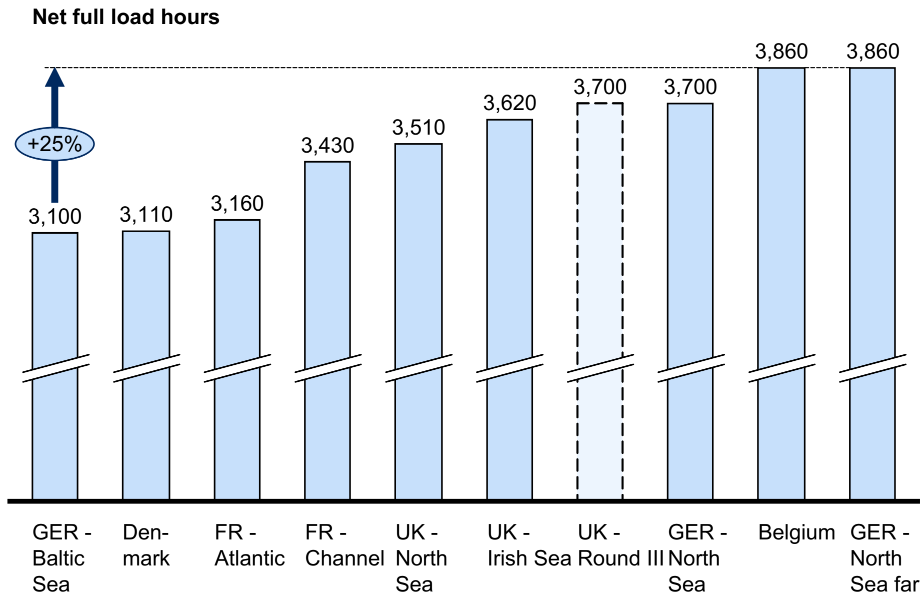

Fig. 3. Net full load hours across scenarios (Rounded to closest 10^1).

ensure that they incorporate and explicitly report these relevant parameters.

4.2. Comparison of full load hours

As described above, the number of net full load hours a turbine can run during a year is a major determinant of the amount of power that can be produced.[26] Fig. 3 shows net full load hours across the set of scenarios, resulting from the respective wind resources in the different geographic locations. Note that the averaged values for the scenarios are an approximation—individual OWP sites can have significantly higher or lower specific wind speeds.

Development areas with small wind resources of around 3100 full load hours are *GER—Baltic Sea*, *Denmark,* and *FR—Atlantic.* At the other end of the range, *Belgium*, *GER—North Sea, GER—-North Sea Far* and *UK—Round III* benefit from strong winds, resulting in 3700 full load hours or more. The other British development areas and the one in the English Channel end up in the middle, with a range between 3400 and 3600 full load hours. With the exception of Scottish territories in the Irish Sea, *UK—Round III* wind resources are, on average, not much stronger than other offshore development areas.

The spread between the scenarios with the smallest and the highest numbers of full load hours is 25%. This is much smaller than the spread of investment costs presented above—even when accounting for the influence of the grid regulation. However, the impact of net full load hours – which essentially represents the utilization of the wind power plant – is still significant.[27] This importance is reflected in the amount of time and resources that OWP developers invest into optimizing wind park design and O&M strategies as well as in a broad strand of R&D-related literature on wind farm layout optimization.[28]

4.3. Comparison of profitability

Before discussing the results with respect to profitability, it is remarked once again that the conducted economic analysis adopts a simple national economic basis. Thus, the below-presented IRR values should not be interpreted as the profitability that individual offshore companies may face, as financing costs, tax effects, etc. are not included as explained above. However, the obtained values are a good indicator for unbiased comparisons between the OWP scenarios, which reflect the characteristics of the different national offshore wind development areas. Fig. 4 presents the profitability of the sample in descending order.

Currently, the offshore wind power markets in the UK and Germany have the greatest profitability potential in Europe. The scenarios *UK—North Sea* and *UK—Irish Sea* have the highest profitability values, with an IRR of around 18.5%. Closely followed by the scenario *GER—North Sea* with a profitability of 17.8% and then at a little more distance *GER—North Sea Far,* reaching an IRR of 14.5%.[29]

Interestingly, outlooks for these two countries are strongly diverging. Future UK projects in *Round III* will have much lower profitability, because the OWP sites are located in comparably deep waters and are (partly) at large distances from the shore. The resulting IRR, of only 10.1%, ranks second from the bottom in the sample. Contrarily, expected profitability of future German projects will be less susceptible to increasing distance to shore and greater water depth as the German regulation compensates for these factors with the adjustable duration of the FIT. This finding is remarkable as the British Round III territories constitute by far the largest share of potential offshore wind power capacity in Europe. Another insight lies in the fact that even within a given national regulation there can be quite significant differences in financial attractiveness due to variations in geographic conditions. This emphasizes the necessity for OWP developers to

[26] Given identical turbines as modeled in the hypothetical OWP scenarios.

[27] If the *GER—Baltic Sea* scenario was endowed with the same wind resources as the scenarios with the most full load hours, it would be the most profitable of all scenarios. For an overview of the profitability compare Section 4.3.

[28] For a comprehensive overview of the literature on wind farm layout optimization compare Salcedo-Sanz et al. (2011).

[29] Supposing the previous remuneration scheme for offshore wind power in Germany (15 ct/kWh for a period of 12 years with the same possible extension as presented above) the IRR for *Germany—North Sea* is roughly 4.2 percentage points lower and *Germany—North Sea Far* loses around 3.5 percentage points in profitability.

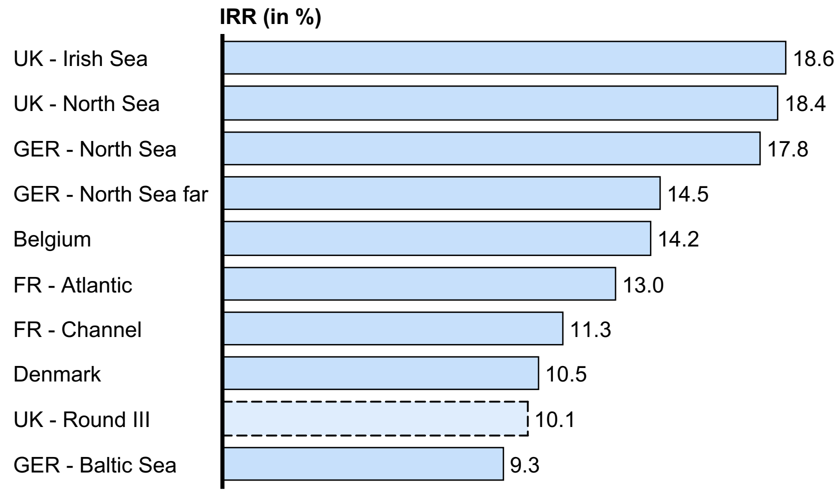

Fig. 4. Comparison of IRR (in %) for set of OWP scenarios.

perform intensive due diligence during their location choice process.

The *Belgium* and the *FR—Atlantic* scenarios, achieving an IRR of around 13–14%, fill the middle positions of the profitability ranking. Both scenarios have in common the upside potential for their profitability, so that these markets may become even more attractive. For Belgium this is due to the minimum price that is currently paid for green certificates. Supposing an increase of the certificates price in the future, the profitability of the Belgian OWPs would improve. Regarding the French scenario, there is uncertainty related to the ongoing tender process. The defined scenario uses the middle of the price range that is specified by the French administration. Applying the upper limit of this price range would result in an IRR of around 17%, being close to the top scenarios.

A mixture of scenarios from France, Denmark, and Germany occupies the lower end of the profitability ranking. The common factor of these scenarios is a relatively low mean wind speed, translating into the low full load hours discussed above. The *FR—Channel* Scenario achieves an IRR of 11.3% resulting from the rather low FIT.[30] The low IRR of 10.5% for *Denmark* has limited predictive power for future parks, as OWPs are tendered individually in Denmark. The previous tenders of, for example, Horns Rev and Rodsand had even lower remuneration – around 7.0 and 8.5 ct/kWh respectively – and would have yielded little to no profit in the economic model. Obviously, costs were lower in the past, as discussed above. Nevertheless, the 80% jump increase for the Anholt tender outcome indicates that OWP operators adjust their bids to earn reasonable profits. Thus, future tenders may result in higher remuneration levels, increasing the attractiveness of the offshore wind market in Denmark. The *GER—Baltic Sea* scenario only achieves a profitability of 9.3% as a consequence of the rather short FIT period and the subsequent long exposure to competitive market prices.

Compared with the above mentioned rankings of KPMG and Ernst and Young, there is similarity of results, for the most part. However, there are also three differences. First, the relative ranking of France is higher, mainly because the analysis at hand incorporates new information of the ongoing tender process. Second, the scenario approach allows for a more granular assessment and can distinguish between differing attractiveness levels within one country. Third, as a consequence of this, the outlook of the UK does not appear as bright.

To put these results into perspective, it is necessary to acknowledge the respective levels of risk associated with different OWP locations. From the perspective of an investor, the attractiveness of an investment does not solely manifest itself in the level of profitability but also in related risks (Lüthi and Prässler, 2011; Dinica, 2006). The larger the distance to shore and the higher the water depth, the more risk is incurred with respect to the construction process and the technologies employed. Additionally, investors' risk levels change depending on the type of policy support instrument set by the national regulator. FITs used in Denmark, France, and Germany have lower market exposure and therefore lower risk than the freely traded green certificates applied in Belgium and the UK. Scenarios that score lower in the ranking of financial attractiveness as defined in this paper such as *GER—Baltic Sea* or *Denmark* may still offer attractive investment opportunities from a holistic evaluation approach because they are (a) subject to less challenging geographic conditions and thus less construction and technology risk and (b) carry little regulatory risks.

In sum, the offshore wind power markets in the UK and Germany are currently most attractive in terms of profitability, with the former having an unsettled outlook for Round III projects under the current legislation. The markets in France and Belgium follow at a certain distance, but both have potential to improve their attractiveness. The profitability of OWPs in Denmark is currently not competitive in the European context, but future tenders may result in higher remuneration levels.

4.4. Impact of national regulation

The above results show the financial attractiveness of the scenarios when the current national offshore policy support schemes are applied. To illustrate the impact that these national regulations have on financial attractiveness, the following analysis will simulate homogenous regulations across all 10 scenarios. Therefore, a simple FIT of 15 c/kWh[31] for a period of 20 years is assumed. Additionally, OWP developers are assumed to bear the responsibility for the grid connection. The resulting ranking (see Fig. 5) reflects the underlying aptitude for offshore wind power development of the various locations as it is only determined by

[30] The upward potential is similar to the other French scenario.

[31] This value is only illustrative and chosen arbitrarily. However, the relative ranking among scenarios does not change with other reasonable values.

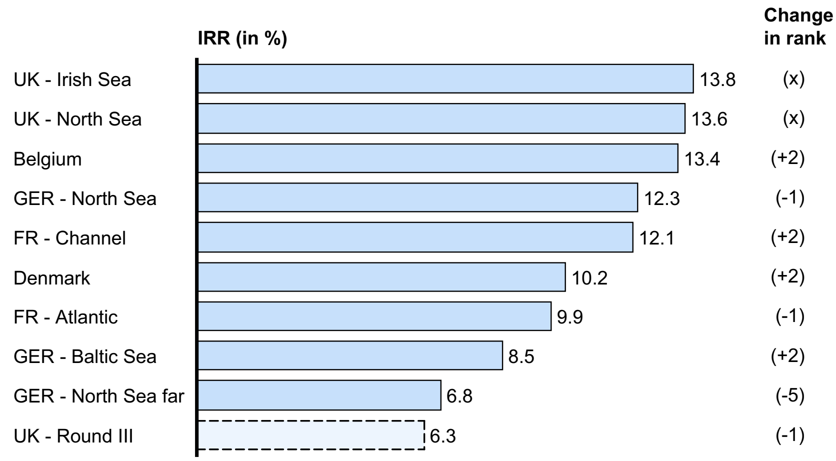

Fig. 5. Comparison of IRR (in %) for the set of OWP scenarios in the "Level playing field—simulation".

Table 7
Changes of IRR (in percentage points) with respect to variations in input parameters.

Scenario	IRR (Base Case) (%)	Electricity price/Green certificate (%)		Investment costs (%)		OPEX & Electricity price/Green certificate (%)
		−20	+20	−20	+20	+2 annually
Belgium	14.2	−1.8	+5.5	+5.4	−3.4	+2.6
Denmark	10.5	−0.2	+0.2	+5.1	−3.5	−0.8
FR—Channel	11.3	0	0	+5.1	−3.4	−0.9
FR—Atlantic	13.0	0	0	+4.7	−3.2	−1.0
GER—Baltic Sea	9.3	−1.5	+1.2	+8.4	−5.7	−0.1
GER—North Sea	17.8	−0.8	+0.7	+10.4	−6.6	−0.2
GER—North Sea Far	14.5	−0.4	+0.4	+8.2	−5.4	−0.5
UK—Round III	10.1	−5.0	+4.7	+4.4	−3.0	+2.6
UK—Irish Sea	18.6	−6.4	+6.5	+6.7	−4.3	+2.7
UK—North Sea	18.4	−6.3	+6.5	+6.6	−4.3	+2.7

their geographical parameters. Note that the absolute IRR values shown in Fig. 5 have limited explanatory power; the key insight here is the relative positioning of scenarios.

In this "Level playing field—simulation" several scenarios change ranks. Most notably, *GER—North Sea Far* drops from being fairly attractive to ranking second to last. This is largely because under regular German offshore wind regulation (a) grid connection costs are born by the TSO, and (b) the duration of remuneration support increases for OWPs that are located far off shore and in deep waters. Without these incentives, the high capital costs associated with unfavorable geographic conditions translate into a financially unattractive setting. Consequently, *UK—Round III,* which has similar challenging geographic conditions, remains an unattractive scenario. The rest of the changes in ranking are attributable to the increased capital costs for the other two German scenarios and the downgrading of the *FR—Atlantic* scenario due to the equalized compensation. Without the influence of support policies, the scenarios that seem best suited for offshore wind power development from a financial perspective are *UK—Irish Sea, UK—North Sea* and *Belgium*. All these scenarios have short distances to shore, rather shallow waters and strong wind speeds in common.

The above results illustrate how policy support instruments determine the financial attractiveness of OWPs and thereby also the European offshore wind power market landscape. The shortly mentioned historic dynamics of support policies (Section 3.2) indicate that policy makers are aware of this. However, energy policy makers should also be aware that not only the often discussed choice of primary support instruments (e.g., FIT or green certificates) and total remuneration levels matter, but also the general regulatory framework. Secondary aspects such as the regulation of the grid access have a strong impact on how investors perceive the overall attractiveness of national OWP development areas. In addition, even supposing a homogenous European regulatory landscape, national policy makers can still exert a certain degree of influence on the financial attractiveness by optimizing the permissible locations for offshore wind power. Granting permissions for near-shore OWP development areas can reduce costs significantly. These cost savings bear potential for either increases in profitability levels or reductions in subsidy levels. Naturally, non-financial aspects such as environmental protection and requirements from other stakeholders (for instance, local residents) need to be weighed carefully against these factors (Jay, 2010).

The above findings are of particular importance for policy makers in countries in which offshore wind power regulation is not clearly defined yet, such as the USA and China. For the European context, the above analyses could constitute a starting point for further research on energy policy design, for instance with regards to the prospects of flexible mechanisms under the European Energy Directive.

4.5. Sensitivity analyses

In order to develop an understanding on how strong single parameters influence the profitability results, this section provides some sensitivity analyses. Table 7 shows the sensitivity of the base case IRR for each scenario with respect to (a) ±20% variation in electricity prices/green certificate prices, (b) ±20% variation in investment costs and (c) +2% annual increase in both OPEX and electricity/green certificate prices, which reflects the impact of inflation.

Column three and four show the sensitivity with respect to fluctuating electricity and green certificate prices.[32] The influence of price changes on the OWPs' IRR is highest for the Belgian and UK scenarios because they are exposed to market prices for the entire period under review. The upside potential in Belgium is higher than the downside potential due to the guaranteed minimum certificate price. In contrast, OWPs in Germany and Denmark are only affected by fluctuating electricity prices in the period after the expiration of the FITs. Thus, the overall impact for these scenarios is minor. The German scenarios show nicely how this period and therefore also the market exposure decreases with the prolongation of the FIT period for projects in more challenging geographic conditions, such as *Germany—North Sea Far*. Since the French numeration scheme provides a FIT for 20 years, there is no impact of fluctuating electricity prices for the French scenarios at all. Note that the differences in sensitivity across scenarios highlight the above-mentioned influence of the regulatory regime on the risk level of OWP developers.

Column five and six show the impact of varying investment costs, which is significant for all scenarios. In general IRRs of the scenarios change in the range of roughly ±3–6 percentage points, as a response to a 20% decrease or increase of investment cost. The German scenarios react even stronger with upside potentials of up to +10.4 percentage points. This is due to a timing effect in the IRR calculation.[33] As a consequence of the German Stauchungsmodell, the bulk of revenues accrue in the first 8–10 years, whereas revenues are rather small in the remaining years. This requires much stronger adjustments to the IRR in order to compensate for the changes of investment costs. All other scenario have benefits streams that are evenly spread over 20 years.

Column seven and eight show the response to a 2% annual increase of OPEX and electricity/green certificate prices. Thereby, this analysis simulates an inflation factor. The overall change of IRRs compared to the nominal values in the base case modeling is small – lower than 2.7 percentage points. Generally, the increase in OPEX is (over-) compensated by the increase in revenues. However, countries with fixed, FIT-based revenue streams for most of the time – Germany, France, and Denmark – suffer slightly from rising OPEX.

4.6. *Future scenario*

The above analyses describe the status quo, assuming current costs and state-of-the-art technology. As installed capacity grows, there will be learning throughout the industry ranging from turbine production and foundation design to supply chain efficiency, construction processes, and maintenance strategies. The following analysis conceptualizes a potential mid-term Future Scenario for around 2020. Here, a decrease in investment costs in the order of −20% is assumed, which is the result of a 5% learning rate as suggested by van der Zwaan et al. (2011) and four expected installed capacity doublings for offshore wind during the upcoming 10 years (compare installed capacity in Table 3). Furthermore, it is assumed that the use of more reliable turbines and learning reduce variable cost from 4% to 3% of total investment costs after the initial period.[34] Finally, it is assumed that the greater reliability of turbines, optimization with respect to the layout of OWPs and improvement of O&M strategies reduce the energy loss factor from 14% to 12.5%.[35] Fig. 6 depicts the resulting range of profitability for the set of scenarios.

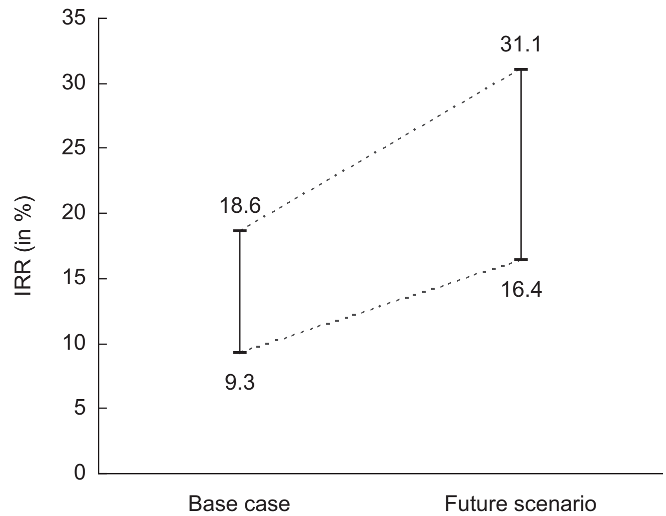

Fig. 6. Comparison of IRR ranges (in %) between the set of scenarios in the base case and in the future scenario.

Applying the current remuneration schemes, the IRR values of all scenarios increase significantly in the *Future Scenario*. The range of attainable IRRs widens, highlighting that it will become even more important for developer companies to screen carefully for optimal OWP sites. In general, IRR values in the *Future Scenario* are quite high, which could allow for reductions in national support schemes. To yield the same profitability levels as in the base case, remuneration levels in the *Future Scenario* could be roughly 25% lower, depending on each respective scenario. Note that this number is rather an indicative value than the result of an in-depth cost projection assessment. Still, the order of magnitude is informative and hints to two conclusions. Firstly, it shows that energy policy makers will have room for moderate decreases in current remuneration levels. Secondly, it reveals that a step change in the cost structure of offshore wind power is not in the offing in the near future.

5. Conclusion

Offshore wind power will be an essential element of the future power supply in Europe, as it is a large-scale carbon-free technology. Hence, many European countries have set ambitious target for offshore wind capacity. In this context, a systematic and comprehensive assessment of the financial attractiveness of the offshore wind power markets in different European countries is meaningful.

This paper conducts an objective comparison of the financial attractiveness between scenarios from the major European wind power markets. The defined scenarios reflect both specific geographic parameters such as water depth, distance to shore, wind resources and the respective regulatory setting with respect to remuneration levels and grid connection responsibility. Employing a DCF model, the profitability measure IRR is used to analyze financial attractiveness. The result of this economic analysis is a

[32] Green certificates are only applicable to the scenarios from the UK and Belgium.

[33] Calculations using the internal rate of return are responsive to cash flow timing; discounting with WACC would yield similar results for all scenarios.

[34] As presented above, some reports (KPMG, 2010; RenewableUK, 2011) already assume variable costs in the range of 3% of total investment costs.

[35] Middle value of the ranges provided in Blanco (2009) and EWEA (2009b).

ranking of profitability levels among hypothetical OWPs from the key European offshore wind countries.

Before summarizing the results, it is meaningful to outline briefly the potential limitations of the chosen approach. First, there is only a limited amount of reliable data available on the costs accrued in the offshore wind industry. Developer companies have limited track records of cost data, and existing real project data is often treated as confidential information. Thus, the cost data found in the literature exhibits broad ranges so that the presented data is subject to a certain degree of uncertainty. Second, input parameters of the economic model reflect state-of-the-art knowledge on costs and current national regulations. Naturally, these parameters are subject to constant change and therefore only have a snapshot character. Third, as explained above, the assessment is conducted on a simple national economic basis to ensure comparability. Hence, the presented IRR values do not directly reflect company profitability as they deliberately refrain from issues such as national taxation and company-specific financing structure.

The results of the economic analysis show that the markets in the UK and Germany comprise the most profitable offshore wind development areas in the financial attractiveness ranking: *UK—Irish Sea*, *UK—North Sea*, and *GER—North Sea*, *GER—North Sea Far*. However, both countries also have areas with less attractive characteristics. *GER—Baltic Sea* has comparably poor wind resources, and the *UK—Round III* scenario suffers from high investment costs driven by unfavorable geographic parameters and responsibility for the grid connection. The fact that the *UK—Round III* scenario ranks second from the bottom in financial attractiveness indicates that prospects for the UK and Germany may diverge in the mid- to long-term and that, regarded from an industry development perspective, the offshore wind industry in the UK may be at a disadvantage compared to that of Germany. The *Belgium, FR—Channel, FR—Atlantic,* and *Denmark* scenarios fill the middle ranks of the assessment in the corresponding order.

Besides the profitability ranking, the economic analysis reveals remarkable findings regarding differences in cost structures. The spread between the least cost and highest investment cost scenario amounts to 61%. The main influencing factors are varying water depths and distances to shore. This underlines the paramount importance of the geographic conditions of an OWP. In addition, a smaller portion of the spread is attributable to differing regulations of grid connection. Literature discussing investment costs of offshore wind power should therefore strive to be as precise as possible about the underlying assumptions. Further research and more recent data on the dependency of cost on water depth and distance to shore would also be critical in order to mirror the constantly changing cost dynamics and technology advancements.

The above indicated influence of national regulation is scrutinized in a separate analysis, which assumes homogenous European regulation across the set of scenarios. The corresponding financial attractiveness ranking then changes considerably. Scenarios now rank solely according to their geographic characteristics such as water depth, distance to shore and wind speeds. The scenario *GER—North Sea Far* is especially salient in this context, dropping five ranks. Hence, it becomes evident that national regulation has a strong influence on shaping the European offshore wind market landscape. Energy policy makers do not only influence the financial attractiveness through direct support instruments, but also impact the cost structure of OWPs by specifying grid connection regulations. Furthermore, energy policy makers have an indirect influence when determining the location of OWP development areas, as the geographic conditions strongly affect profitability. Ultimately, national regulations thereby determine the appetite of investors for engagements in offshore wind power.

Finally, an extension of the basic modeling in the form of a *Future Scenario* attempts to pre-empt potential improvements of investment costs, O&M costs and the available number of net full load hours during the upcoming decade. Profitability in this scenario increases significantly so that remuneration levels across the sample could be lowered by roughly 25% to achieve the current profitability values.

In conclusion, the presented findings contribute to the existing literature by deepening the understanding of the influence of national support policy schemes for offshore wind and by creating transparency on costs and profitability levels of the key European offshore wind markets. These findings can serve as useful guidance for energy policy makers and scholars alike.

Acknowledgements

We are thankful to Tobias Grieshaber, Christian Friebe and Jens Uhlenbrock for helpful comments. The second author also wants to thank Dominique Demougin for the given flexibility.

Appendix A

See Table A1.

Appendix B

See Tables B1 and B2.

Table A1
Overview of Offshore Wind Park development areas used.

Country	Name	Scenario	Status	Distance to shore (km)	Water depth (m)		Wind speed (m/s)
					Min.	Max.	
UK	Dogger Bank Tranche A	UK—Round III	Conceptual	151	25	30	9.72
	Dogger Bank	UK—Round III	Conceptual	197	18	63	9.83
	Atlantic Array Wind Farm	UK—Round III	Conceptual	25	35	50	9.81
	Moray Firth Eastern	UK—Round III	Conceptual	27.5	35	60	10.12
	Firth of Forth Phase 1	UK—Round III	Conceptual	37.9	31	71	9.78
	Hornsea	UK—Round III	Conceptual	96.2	30	40	9.31
	Hornsea Project 1 Block 2	UK—Round III	Conceptual	99.5	25	40	9.41
	Hornsea Project 1 Block 1	UK—Round III	Conceptual	99.5	25	40	9.36

Table A1 (*continued*)

Country	Name	Scenario	Status	Distance to shore (km)	Water depth (m)		Wind speed (m/s)
					Min.	Max.	
	Irish Sea	UK—Round III	Conceptual	37.7	26	74	9.82
	Navitus Bay Wind Park	UK—Round III	Conceptual	19.8	28	58	9.73
	rampion	UK—Round III	Conceptual	18.1	11	50	9.76
	East Anglia 1	UK—Round III	Conceptual	44	32	41	9.73
	East Anglia 2	UK—Round III	Conceptual	54	5	73	9.52
	Islay	UK—Round III	Conceptual	16.1	30	50	10.90
	Argyll Array	UK—Round III	Conceptual	5	35	45	11.19
	Greater Gabbard	UK—North Sea	Construction	36	20	32	9.87
	Lincs	UK—North Sea	Construction	8	10	15	9.15
	London Array I	UK—North Sea	Construction	20	25	25	9.94
	Sheringham Shoal	UK—North Sea	Construction	23	15	22	9.16
	Westermost Rough	UK—North Sea	Consented	8	10	25	9,19
	Humber Gateway	UK—North Sea	Consented	8	11	18	9.19
	Teesside	UK—North Sea	Consented	1.5	7	15	9.39
	Thanet	UK—North Sea	Operation	12	14	23	10.06
	Gunfleet Sands	UK—North Sea	Operation	7	2	15	9.93
	Ormonde	UK—Irish Sea	Construction	9.5	17	22	9.78
	Walney I	UK—Irish Sea	Operation	14	19	28	9.78
	Walney II	UK—Irish Sea	Construction	14	25	30	9.78
	Gwynt y Mor	UK—Irish Sea	Consented	13	12	28	9.78
	West of Duddon Sands	UK—Irish Sea	Consented	15	17	24	9.78
	Robin Rigg (Solway Firth)	UK—Irish Sea	Operation	11	4	13	9.55
	Rhyl Flats	UK—Irish Sea	Operation	8	6	12	9.78
Belgium	Thornton Bank I	Belgium	Operation	27	12	28	10.20
	Thornton Bank II	Belgium	Construction	27	12	28	10.20
	Thornton Bank III	Belgium	Consented	26	12	28	10.20
	Belwind 1	Belgium	Operation	46	20	37	10.16
	Belwind 2	Belgium	Construction	46	20	37	10.16
	Bank zonder Naam	Belgium	Consented	37	16	32	10.20
Germany	Alpha Ventus	GER—North Sea	Operation	45	30	30	9.92
	Amrumbank West	GER—North Sea	Consented	36	20	25	9.77
	Borkum Riffgrund 1	GER—North Sea	Consented	34	23	29	9.92
	Borkum Riffgrund West	GER—North Sea	Consented	53	30	35	9.94
	Borkum West II	GER—North Sea	Consented	52	29	33	9.92
	Butendiek	GER—North Sea	Consented	34	16	22	9.79
	Delta Nordsee 1	GER—North Sea	Consented	37	25	33	9.79
	Delta Nordsee 2	GER—North Sea	Consented	40	29	33	9.79
	Gode Wind	GER—North Sea	Consented	32	26	35	9.87
	Gode Wind II	GER—North Sea	Consented	33	26	35	9.87
	Innogy	GER—North Sea	Consented	30	22	22	9.77
	Meerwind	GER—North Sea	Consented	23	23	26	9.77
	Meg Offshore	GER—North Sea	Consented	45	27	33	9.97
	Nordergründe	GER—North Sea	Consented	13	2	18	9.95
	Riffgat	GER—North Sea	Consented	14.5	18	23	9.86
	Bard 1	GER—North Sea Far	Construction	89	39	41	10.02
	Dan Tysk	GER—North Sea Far	Consented	70	23	31	9.97
	Deutsche Bucht	GER—North Sea Far	Consented	87	40	40	10.01
	He Dreiht	GER—North Sea Far	Consented	85	39	39	10.00
	Hohe See	GER—North Sea Far	Consented	90	26	39	10.50
	Global Tech	GER—North Sea Far	Consented	93	39	41	10.05
	Nördlicher Grund	GER—North Sea Far	Consented	84	25	25	10.00
	Sandbank 24	GER—North Sea Far	Consented	90	30	30	10.80
	Veja Mat	GER—North Sea Far	Consented	91	39	41	10.03
	Baltic 1	GER—Baltic Sea	Operation	15	15	19	8.95
	Arkona Becken	GER—Baltic Sea	Consented	35	21	38	8.64
	Geofre	GER—Baltic Sea	Consented	20	20	20	n.a.
	Baltic 2	GER—Baltic Sea	Consented	31	20	35	8.82
	Wikinger	GER—Baltic Sea	Consented	30	25	45	8.64
France	Saint-Brieuc	FR—Atlantic	Consented	22.8	20	39	8.99
	Saint-Nazaire	FR—Atlantic	Consented	16	10	20	8.72
	Fecamp	FR—Channel	Consented	17.2	25	30	9.41
	Courseulles	FR—Channel	Consented	13.8	21	25	9.12
	Le Tréport	FR—Channel	Consented	19.1	8	24	9.58
Denmark	Anholt	Denmark	Construction	21	15	19	8.81

Table B1

Increase in offshore investment cost due to distance to coast (in km)

Cost split	5	10	15	20	25	30	35	40	45	60	75	93.8	112.5	131.3	150	> 200
Turbine	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772
Foundation	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
Installation	465	471	476	482	488	494	500	506	511	559	607	659	712	764	816	964
Inst.-turbine	*155*	*156*	*156*	*157*	*157*	*158*	*159*	*159*	*160*	*164*	*169*	*174*	*180*	*185*	*190*	*205*
Inst.-foundation	*155*	*156*	*156*	*157*	*157*	*158*	*159*	*159*	*160*	*164*	*169*	*174*	*180*	*185*	*190*	*205*
Inst.-grid	*155*	*159*	*164*	*169*	*173*	*178*	*183*	*187*	*192*	*230*	*269*	*310*	*352*	*394*	*436*	*554*
Grid connection	133	146	159	172	185	198	211	224	236	275	314	362	411	459	507	702
Other	79	80	81	82	82	83	84	85	85	86	87	87	88	88	88	89
Total cost	1801	1821	1840	1860	1879	1899	1919	1938	1956	2044	2132	2233	2334	2434	2535	2879

Increase in offshore investment cost due to water depth (in m)

Cost split	15	20	25	30	35	40	45
Turbine	772	772	772	772	772	772	772
Foundation	352	409	466	545.5	625	762.5	900
Installation	465	465	465	535	605	605	605
Inst.-turbine	*155*	*155*	*155*	*162*	*169*	*169*	*169*
Inst.-foundation	*155*	*155*	*155*	*211*	*267*	*267*	*267*
Inst.-grid	*155*	*155*	*155*	*162*	*169*	*169*	*169*
Grid connection	133	133	133	133	133	133	133
Other	79	82	85	88.5	92	98.5	105
Total cost	1801	1861	1921	2074	2227	2371	2515

In EUR/kW, Original data without shading, interpolated values shaded gray, assumed values in italics.

Table B2

Scale factors for adjustments due distance to coast (in km)

Scale factor	5	10	15	20	25	30	35	40	45	60	75	93.8	112.5	131.3	150	> 200
Turbine	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Foundation	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Installation	0.92	0.93	0.94	0.95	0.97	0.98	0.99	1.00	1.01	1.11	1.20	1.30	1.41	1.51	1.61	1.91
Inst.-turbine	*0.98*	*0.98*	*0.98*	*0.99*	*0.99*	*0.99*	*1.00*	*1.00*	*1.00*	*1.03*	*1.06*	*1.10*	*1.13*	*1.16*	*1.20*	*1.29*
Inst.-foundation	*0.98*	*0.98*	*0.98*	*0.99*	*0.99*	*0.99*	*1.00*	*1.00*	*1.00*	*1.03*	*1.06*	*1.10*	*1.13*	*1.16*	*1.20*	*1.29*
Inst.-grid	*0.83*	*0.85*	*0.87*	*0.90*	*0.93*	*0.95*	*0.98*	*1.00*	*1.02*	*1.23*	*1.43*	*1.66*	*1.88*	*2.10*	*2.33*	*2.96*
Grid connection	0.60	0.65	0.71	0.77	0.83	0.87	0.94	1.00	1.06	1.23	1.41	1.62	1.84	2.05	2.27	3.14
Other	0.94	0.95	0.96	0.96	0.97	0.98	0.99	1.00	1.01	1.02	1.03	1.03	1.04	1.04	1.04	1.05
Total cost	0.93	0.94	0.95	0.96	0.97	0.98	0.99	1.00	1.01	1.06	1.10	1.15	1.20	1.26	1.31	1.47

Scale factors for adjustments due to water depth (in m)

Scale factor	15	20	25	30	35	40	45
Turbine	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Foundation	0.645	0.750	0.854	1.000	1.146	1.398	1.650
Installation	0.869	0.869	0.869	1.000	1.131	1.131	1.131
Inst.-turbine	*0.957*	*0.957*	*0.957*	*1.000*	*1.043*	*1.043*	*1.043*
Inst.-foundation	*0.735*	*0.735*	*0.735*	*1.000*	*1.265*	*1.265*	*1.265*
Inst.-grid	*0.957*	*0.957*	*0.957*	*1.000*	*1.043*	*1.043*	*1.043*
Grid connection	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Other	0.893	0.927	0.960	1.000	1.040	1.113	1.186
Total cost	0.868	0.897	0.926	1.000	1.074	1.143	1.213

Starting value shaded gray, assumed total capital costs of 3800 EUR/kW.

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Chapter 5

Conclusion

1 Conclusions

A large-scale transition from fossil fuel energy technologies to low-carbon technologies is needed to combat GHG emissions. Renewable energy technologies such as wind power will play a crucial role in this transition. Currently, renewable energy support policies are needed to drive the expansion of wind power and other RETs. Policymakers have an interest in designing smart support policies that target eliminating barriers and fostering the fast and efficient deployment of RETs. The central market agents that act on the provided incentives are RET developers and investors. This dissertation strives, therefore, to generate recommendations for policymakers by analyzing existing barriers and support policies regimes through the eyes of developer companies.

The following section first synthesizes this dissertation's main contributions and results on a high level. It then provides a short synopsis of the main findings of each of the three conducted research studies. Lastly, areas for further research are derived and discussed.

1.1 Key contributions

The research presented in this dissertation adds to existing knowledge in three ways. First, it provides a rich set of empirical data. Building on extant literature on deploying wind power technologies, the presented work provides quantifiable evidence on the importance of policy measures that mitigate risk, regulatory stability, and how developers evaluate the relationship between risks and returns (Dinica 2006). Study I gathers 4,749 choice decisions from 119 onshore wind power developers to derive conclusions on their preference structure regarding development attributes, differences in preferences across various types of developers (Langniss 1996), and on different geographies. Study II generates in-depth empirical insights from interviews with experts representing almost 75% of the offshore development landscape in Germany and the UK. Lastly, Study III combines real-life policy framework regulations with empiric wind resource data and state-of-the-art cost data to derive a ranking of the financial attractiveness for 10 European OWP location scenarios.

Second, the work conducted in Studies II and III adds substantially to existing knowledge on the dynamics of developing offshore wind power. Because deploying large-scale offshore wind power is fairly novel, only a limited amount of scientific literature has investigated the barriers and drivers to further expansion (Snyder & Kaiser 2009; Bilgili et al. 2011; D. Toke 2010). The broad set of insights derived from the expert interviews in

Study II builds on these studies and deepens the understanding of the development dynamics in the two most important offshore markets—the UK and Germany. The comparison yields insights into which regulatory practices work well and explains why. Study III substantiates the findings from Studies I and II by objectively comparing the financial attractiveness of offshore wind power projects in five European countries.

Third, this dissertation suggests a more holistic framework of the determinants that shape the attractiveness of policy regimes (see Figure 3, Chapter 1). The scientific community has developed a large body of literature on policies regulating how renewable energy technologies are deployed and diffused. Most barriers to development and the policy instruments addressing those barriers have been described previously in various contexts. The framework presented in this dissertation offers two benefits. First, it proposes that from the perspective of developer companies, these barriers and policy instruments can be consolidated into the three determinants of attractiveness: project profitability, level of risk for developers, and complexity and speed of development process. Second, it offers a more comprehensive perspective on development processes because it encompasses all of the relevant aspects. In particular, it highlights the importance the so-called secondary regulatory aspects that are not linked directly to the primary support mechanism but are still decisive for deploying RETs successfully. Such secondary regulatory aspects include, for example, financing support programs from development banks or grid access regulations.

1.2 Main results and implications for policy makers

Expanding the policy focus beyond remuneration to minimizing risk

The public debate on renewable energy support tends to center primarily on its financial dimension. As the general public becomes more savvy on energy policy topics, the media and politicians frequently discuss feed-in tariff levels. In Germany, the term "Solarschulden"—describing the cumulated future payment liabilities of all installed solar PV installations—has become a well-known controversial expression. Without a doubt, this is a very important discussion because society, either via tax payers or via electricity consumers, pay for these subsidies. If the total subsidy payments rise above the threshold of public acceptance, support for renewable energy might deteriorate, therefore putting expansion goals at risk.

This dissertation's findings should encourage policymakers to consider additional aspects of deploying RETs. The menu of support measures available is broad including many non-financial support instruments. The results indicate that developers highly value measures that mitigate risk such as developing clear standards for permitting procedures, shortening the duration of administrative processes, providing authorities with sufficient resources to avoid delays, or establishing legal security and enforceability of developers' rights. This latter aspect, for example, emerges as the most important attribute for onshore wind power developers, even topping the aspect of remuneration.

These findings empirically support the results of other researchers (Mendonça et al. 2009; Menichetti 2010). These "soft factors" are usually not assessed in economic modeling, partly because it is difficult to gauge their true value to investors or to society. The benefits are real, however, and help improve both the effectiveness and efficiency of renewable energy policy. For solar PV energy, Lüthi and Wüstenhagen (2012) have shown how the value of intangible assets such as stable policies and the duration of permitting procedures can be translated into equivalent remuneration levels. In a similar fashion, this dissertation shows the utility values of eliminating corrupt behavior among authorities or shortening the duration of administrative processes.

Furthermore, the analyses of this dissertation's three studies suggest that many risks are "perceived" risks. If policymakers and authorities create trust and confidence among developer companies, the required risk premiums are reduced. Comparisons of the permitting procedures for offshore wind power in the UK and Germany indicate that a collaborative, can-do attitude and openness to reaching practical compromises on challenges go a long way toward reducing perceived risks.

Many of the main barriers to developing wind power development can be influenced by regulators' decisions and actions. Examples include the reliability, clarity, and stability of support schemes, permitting procedures, and grid access regulations. Recognizing this pivotal capacity empowers policymakers and authorities to play an active role in overcoming those barriers. On another positive note, some measures that mitigate risk are inexpensive to implement. The societal payback on comparatively small investments, such as employing additional administrative case handlers, could be enormous.

The importance of implementing design choices for policy instruments

When it comes to renewable energy policy, much has been discussed about the advantages and disadvantages of primary support policy instruments—most prominently feed-in tariff and green certificate systems (Menanteau et al. 2003; Palmer & Burtraw 2005). Admittedly, choosing the primary support mechanism is important and entails repercussions for the speed and cost of renewable deployment (D. Toke et al. 2008). The research in this dissertation now suggests that implementation design choices are just as important. The introduction of the new acceleration model for offshore wind power in Germany illustrates this point perfectly. A seemingly small change to the duration of the FIT payments creates repercussions not only on profitability levels but also on risks structures, financing options and costs, and potentially even siting decisions for German OWPs.

Thus, to determine the overall attractiveness—and ultimately the effectiveness—of a policy regime, it is beneficial to adopt a comprehensive perspective. Equally as crucial as the specific implementation design of the primary support mechanisms are suitable secondary regulatory aspects. For example, the analyses in Study I show that onshore wind power developers derive little to no utility from an investment environment that offers high levels of remuneration, short permitting procedures, and favorable grid access regulations but suffers from a lack of legal stability. Study II suggests that in developing offshore wind power, even the most promising profitability prospects are spoiled if ill-defined grid access regulations jeopardize a project through delays and legal uncertainties.

The key message to policymakers is as simple as it may be unpleasant: details matter. The studies in this dissertation show how seemingly minor aspects of implementing support policies can have significant repercussions for how developers perceive the attractiveness of the policy regime as a whole. Thus, policymakers need to adopt the perspective of the developer and investor companies to gain a thorough understanding of how policy design specifications effect the behavior of market participants. As the case of the British offshore wind development practices illustrate, close interaction and collaboration among competent authorities and developer companies can be a powerful way to achieve this perspective. The unpleasant part of this message is that addressing and fine-tuning the details of secondary regulatory aspects requires tedious efforts. Yet it also entails great opportunities to enhance both the effectiveness and efficiency of renewable energy support policies.

The following section presents a short summary of each individual study's findings. It describes the key results and highlights the resulting implications for policymakers and regulatory authorities. For more granular discussions of each study's results, refer to the Results sections of each respective study in Chapters 2, 3, and 4.

1.3 Study I

Study I aims to determine and quantify the preference structures of onshore wind power developers with respect to various policy measures. The published paper that discusses this study contributes to the existing literature in three ways.

First, it introduces multivariate, adaptive choice-based conjoint analysis as a fairly novel method in energy policy research. The study suggests that conjoint analysis could be employed as a scenario tool to gauge the potential effects of specific policy measures on the investment behavior of wind energy project developers. Second, the paper provides a quantitative, empirical dataset of developers' preferences in the US and Europe. This data quantifies how much developers value specific development framework conditions and which utility they would derive from targeted improvements. The value of so-called soft factors for developing RETs, such as a secure and stable legal environment, is determined by measuring the respective utility values they provide for developers. Third, it indicates to an extent how these findings differ among various groups of developers and detects regional differences with respect to the two most mature wind energy markets: the EU and the US. The study's results can be summarized in four concrete findings.

First, wind energy project developers place high values on risk mitigation measures. High levels of legal security, keeping administrative processes efficient, and favorable grid access regulations are important attributes for developers. Next to remuneration support, which ranks second in importance, regulators should focus on measures aimed at minimizing risk when designing support policies that promote wind energy.

Second, developers engage in non-compensatory decision-making in the presence of so-called knock-out conditions such as corruption or very low remuneration levels. In such cases, they will refrain from investing even if all other framework conditions are favorable. The conjoint analysis reveals how policymakers can achieve quick wins and drastically improve the perceived attractiveness of a given policy regime by eliminating such knock-out criteria.

Third, the analysis shows that the preferences of the respondents are similar across regions, types, sizes, and value chain foci of the developer companies. Hence, it is likely that preference structures can be transferred and learning from one country can be leveraged in other countries—at least in other developed countries. Still, regulators need to be aware of differences such as cultural factors and degrees of familiarity with policy instruments.

Fourth, although preference structures tend to be similar, this does not mean that all regulators should take identical measures to improve the attractiveness of their wind development environment. Measures that are most effective for enhancing attractiveness strongly depend on the prevalent framework conditions. For example, in a scenario representing a Southeastern European policy context, the most effective measure to improve utility for developers is to shorten the average duration of administrative processes. In a US scenario, on the other hand increasing remuneration levels would yield the highest utility gains.

1.4 Study II

This empiric study identifies the barriers of offshore wind power development in Germany and the UK through the eyes of developer companies and analyses how regulators can address these barriers with appropriate policies. Analyzing the expert interviews yields 23 distinct findings across a range of aspects associated with developing offshore wind power. The discussion of results highlights the differences between British and German offshore wind power regulations and scrutinizes diverging perceptions among different types of developer companies. When synthesizing these results, five key insights emerge.

First, developers evaluate the perceived attractiveness of a given policy regime in three dimensions, which are coined the “determinants of attractiveness”: (1) project profitability, (2) level of risk for developers, and (3) the complexity and speed of development process (see Figure 3). Each of these is described briefly in the following points:

- Not surprisingly, project profitability is one of the key determinants for attractiveness. The interviews suggest that in the past the attainable profitability levels for OWP projects were insufficient to propel desired expansion. Furthermore, interviewees agree that developing offshore wind power in the UK is more profitable than in Germany.

- The ratio of expected profitability and the level of risk for developers associated with OWP projects is the driving force behind deploying offshore wind power technology. Currently, the risk-return-ratio of offshore wind power is lower than that of more established RETs, such as onshore wind or solar PV, and is thus less attractive. The largest sources of risks in developing offshore wind power are grid connection procedures, a lack of standards and ill-defined timelines for permitting requirements, and legal uncertainties. To reduce these barriers, regulators need to define clear and reliable standards that are sufficiently stable and legally binding.
- Developers advocate that permitting processes could be rendered more efficient by reducing the number of authorities involved, improving coordination among them, and providing sufficient resources.

Second, it is important for energy policy makers and relevant functional authorities not only to remove risks but also change the perception of risks. The analysis of Study II suggests that many risks are perceived risks but still translate into higher risk premiums. If policymakers and authorities can create trust and build confidence among developers that challenges can be overcome, then risks are perceived as less severe. Means to reach this end include a collaborative, can-do attitude, engaging permitting processes, and the willingness to reach practical compromises on challenges. According to the interviewees, the UK's regulatory bodies perform better on these dimensions than do Germany's. These soft measures are instrumental for increasing the effectiveness and efficiency of deploying offshore wind power and are often inexpensive to implement.

Third, policy design choices impact the competitive landscape for different types of developer companies. For example, the barriers for small, independent developer companies are higher in the UK than in Germany because of the more integrative grid access regulations, the lack of financing support instruments, and the more complex and volatility-prone primary support mechanisms. Thus, policymakers need to be aware that by designing policy instruments and regulations, they implicitly impact the level of competition and the structure of industry participants.

Fourth, details matter. Whereas the choice of the primary support mechanism is important, it is not the sole determinant for success. Rather it is the specific implementation design of the primary support mechanism, combined with suitable secondary support elements, that shape the attractiveness of policy regimes overall. The introduction of the new acceleration model under German renewable energy law illustrates this point well. A seemingly small change to the duration of the FIT payments creates repercussions for profitability levels, risks structures, financing options, and costs, and potentially even siting decisions for German OWPs. Thus, policymakers need to adopt the perspective of developer and investor companies to gauge the effect of policy design specifications on market dynamics.

Fifth, according to the expert interviewees, the 2020 expansion goals for offshore wind power could be at risk for both the UK and Germany. Contributing factors include bottlenecks that persistently strain financing markets, high regulatory risks in the permitting procedure, the shortage of experienced personnel for both developers and authorities, and the immaturity of the construction supply chain. In Germany, the grid connection process also proves to be an especially exigent challenge.

1.5 Study III

Study III objectively compares the financial attractiveness between designated OWP sites in five major European wind power markets. It accounts for site-specific geographic parameters such as water depth, distance to shore, and wind resources, as well as regulatory settings with respect to remuneration levels and grid connection responsibility. The result of this economic analysis is a ranking of potential profitability levels. The analysis yields four key findings.

First, developers can find the most profitable conditions for developing offshore wind power in the UK and Germany. From a profitability perspective, the most attractive locations for OWP development are British near-shore locations in the Irish Sea and North Sea, followed by locations in the German North Sea. The high profitability values are driven mainly by attractive remuneration levels and good wind resources in both countries. These findings confirm the results of Study II, adding a quantitative assessment to the qualitatively generated insights from the expert interviews. The profitability comparison also reveals, however, that the British Round III territories, which represent the largest designated offshore wind power sites in Europe, only rank second from the bottom of the list of scenario locations.

Second, the impact of the geographic conditions of an OWP site on attainable profitability is considerable. The countries that have the most attractive scenario locations—the UK and Germany—also have two scenario locations with much less attractive characteristics despite falling under the same policy regime. The impact of comparably poor wind resources (scenario *GER-Baltic Sea*) or high investment costs driven by unfavorable geographic parameters (scenario *UK-Round III*) partly outweigh favorable remuneration support levels. Comparing the cost structures between scenario locations supports this finding. The spread between the least and highest investment cost scenario amounts to 61%. The main influencing factors are varying water depths and distances to shore.

Third, the respective national support schemes for offshore wind power exert a strong influence on shaping the landscape of the European offshore wind market. A simulation assuming homogenous regulations for all countries in which scenarios are ranked solely according to their geographic characteristics shows that the ranking of financial attractiveness changes significantly. Notably, this analysis shows that OWPs located far off shore in the German North Sea drop from being among the most attractive to being the least attractive locations. Energy policy can influence the financial attractiveness of OWPs in three ways: (1) by setting the level of direct remuneration support, (2) by assigning the responsibility for the grid connection to either the developers or the TSOs, and (3) by defining the locations of OWP development areas. Ultimately, national regulations play a huge role in influencing investors to engage in offshore wind power.

Fourth, cost reductions and technology improvements will enable policymakers to reduce remuneration levels for offshore wind power in the mid-term, but only moderately. A simulation in Study III assuming conceivable reductions of investment costs, variable operating costs, and energy loss factors shows that remuneration levels could be roughly 25% lower by 2020 to yield the same profitability levels as today. Although this percentage is an indicative value only, it entails two implications. On the one hand, much-needed reductions in the cost of offshore wind power are likely to materialize in the mid-term and provide leeway to reduce support levels. On the other hand, a step-change in the cost structure of offshore wind power does not seem to be pending in the near future.

1.6 Suggestions for further research

This dissertation contributes to the understanding of how policy regimes affect market participants that drive the development and expansion of wind power technologies. Further research is needed to broaden the acquired insights beyond the scope and limitations of this work into other areas of energy policy research. Further insights regarding how policy-driven incentives translate into actual capacity built-out of renewable energy sources are needed in order to structure them as effectively and efficiently as possible. The described results and limitations of the three studies in this dissertation evoke four promising areas for further research:

First, expanding applied research approaches to other RETs could help create a more holistic understanding of RET diffusion processes. The studies in this dissertation focus only on wind power technologies in order to generate very detailed, thorough insights. Common consensus, though, indicates that transforming to low-carbon energy systems can only succeed when the full range of available RETs is employed (Edenhofer et al. 2010; IPCC 2007a; Luderer et al. 2009; P. del Río 2011). Expanding the research at hand to other renewable RETs would complement the understanding of technology specific barriers to development and help find ways to overcome them most efficiently. This dissertation and other studies (Lüthi & Wüstenhagen 2012; Menichetti & Wüstenhagen 2012) can be a springboard to studying other RETs. For example, the choice-based conjoint methodology would be especially suitable for exploring the development dynamics of more decentralized, end-user-driven technologies such as rooftop solar PV. Conjoint analysis would be a perfect fit to investigate the consumer product characteristics of solar panels and the large number of decision makers. The findings from these offshore wind power studies could be leveraged to foster an understanding of how to scale-up other nascent RETs such as carbon capture and storage or geothermal energy. All these RETs are characterized by fairly novel technologies, a lack of well-defined, standardized regulatory guidelines, high complexity, and large investment requirements. Researchers should provide policymakers with more information on developing these technologies to enable them to establish sound frameworks to govern their future build-out.

Second, greater attention from the scientific community on the dynamic deployment processes of RETs in developing countries will be paramount to achieving sustainable growth on a global level. The research in this dissertation focuses mostly on countries with highly developed track records of deploying renewable energy such as the US, the UK, Germany, and other European countries. Transferring the research approaches to RET deployment in developing countries could yield important insights into how to best incentivize the expansion of RETs where they are most needed. The contributions of Neuhoff et al. (2009) and Sovacool (2010) feature important conceptual and practical recommendations and can be expanded further to reflect the preferences of developer companies and investors on the ground (Flotow & Friebe 2011; Komendantova et al. 2012;

Urmee & Harries 2009). Researchers need to adopt methodologies to reflect additional barriers to developing RETs such as country risk, currency risk, unstable off-take markets, stunted infrastructure, logistical challenges, and potentially corruption.

Third, as the penetration of RETs advances, it will be crucial to investigate gridlock in expanding enabling technologies such as energy storage and transmission technologies. As the transition toward low-carbon energy systems proceeds, the role of enabling technologies should be scrutinized further. In particular, the expansion of intermittent renewable energy sources such as wind and solar power will necessitate large investments in storage and transmission technologies (Hoogwijk et al. 2007; Buijs et al. 2011). Both of these enabling technologies, however, are stalling in many countries (Chen et al. 2009; Beaudin et al. 2010). It is crucial to identify and tackle the root causes of this sluggish development. When investigating these questions, it would be worthwhile to adopt the perspective of potential investors to detect barriers and opportunities to overcome them. In this sense, the methods employed in this dissertation might also be viable research approaches for this work.

Lastly, researchers should provide policymakers with information on the true value of intangible assets such as policy stability, enabling them to make informed decisions related to energy policy design. Among other findings, the results of this dissertation indicate is that the stability and reliability of support systems is pivotal for developers. Although this notion is accepted widely and has been advanced by other research (Wiser & Pickle 1998; Lewis & Wiser 2007a; Barradale 2008; Lüthi & Wüstenhagen 2012), policy stability remains an intangible asset. The question remains how high, exactly, is the value of policy stability? What are the implications of instable and unreliable energy policies? More facts on the worth of policy stability and reliability will be valuable for policymakers, because it essentially represents real option value to foster developing RETs. Two research approaches seem promising to tackle this question. The first approach centers on a comprehensive analysis of empirical evidence of significant policy changes. Examples include the collapse of the Spanish solar PV market due to a sudden introduction of a capacity cap in late 2008 (Solangi et al. 2011; Heras-Saizarbitoria et al. 2011; DB Climate Change Advisors 2009) and the recent discussions to cut legally binding feed-in tariff contracts retroactively—a decision that will potentially cripple the investment propensity of clean-tech investors throughout the industry. Investigating the early impacts of the planned UK electricity reform should also yield interesting insights into the implications of policy changes. Such research should entail detailed descriptions of the effects of these changes in the investor and developer community and generating a plausible metric to measure the impact. Estimating foregone investment volumes or jobs could be a starting point. An alternative approach is to investigate how much the risk premiums for equity investors and debt capital providers increases for renewable energy projects in response to the changes. Higher policy risks—perceived or real—translate into higher interest rates for loans and higher profitability requirements from investors, thus making deploying RETs more expensive. The cumulated value of the increased policy risk premiums multiplied by the targeted capacity expansion goals could be one way to triangulate the value of policy stability.

Ultimately, there is no shortage of questions to be answered by energy policy researchers. Pursuing each of these four research avenues will be important steps toward a better understanding of how policymakers can steer the expansion of renewable energy technologies more efficiently and effectively. In the face of the challenges of climate change and massively growing resource consumption, this endeavor is of paramount importance.

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Statement of contribution

The majority of the research presented in this thesis has been conceptualized and conducted by the author, Thomas Präßler.

Chapters 1, 3 and 5 have been developed autonomously by the author.

Chapter 2 and Chapter 4 have been developed in very close collaboration with fellow scientists Sonja Lüthi and Jan Schaechtele. The below declarations of co-authorship lay out the contributions of each of the authors for these Chapters.

<u>Declaration of co-authors' contributions to the article presented in Chapter 4</u>

The paper is the joint work of the author of this disseration, Thomas Präßler – first author, and second author Jan Schächtele, a fellow researcher and PHD candidate at the European Business School, Universität für Wirtschaft und Recht. All major elements of the research have been developed jointly by the two authors in very close collaboration. In order to distribute workload regarding the collection of data the first author focused on remuneration schemes and wind speed data while the second author focused on cost assumption data.

Both authors shared the workload that arose in the review process with the Journal reviewers.

November, 2011

Thomas Präßler, first author

Jan Schächtele, second author

<u>Declaration of co-authors' contributions to the article presented in Chapter 2</u>

The two authors jointly developed the objective of the study, the research questions and the design of the conjoint analysis.

The second author developed the interview guide for the expert interview series. He acquired interview partners and conducted the majority (19/24) of these expert interviews. The first author was in charge of the remaining interviews, primarily with focus on the US market.

The first author held most expertise with regard to the methodology employed. She designed the survey in Sawtooth SSI Web, handled the study upload, conducted the data analysis using Sawtooth (SSI Web and SMRT), SPSS and most of the subsequent analyses in Excel.

The second author was responsible for the participant acquisition. He identified and contacted the majority of the 1200 developers that were contacted. The first author contributed to this endeavor especially with regard to the US sample.

With respect to writing the first version of the paper, the first author led sections 2.1, 2.4, 2.5; while the second author led sections 2.2, 2.3, and 3. The second author had the majority of the responsibility regarding the sample characteristic evaluations and the representation of the graphs. The introduction (section 1), the interpretation of the results (section 4) and the synthesizing of the conclusions (section 5) were done by both authors in joint collaboration. Several rounds of common revisions and discussions led to the manuscript.

Changes to the first version of the paper were made in two review cycles with the Journal reviewers. Again, the two authors did most amendments to the document jointly, while the second author mainly led the responses to the reviewers.

November, 2011

Sonja Lüthi, first author | Thomas Präßler, second author

Tools and Resources

A number of standard software tools were used for data collection, processing, modeling and presentation.

Chapter 2

Data collection and data processing have been conducted with an academic license of Sawtooth SSI Web 7 Version 7.0.10 and Microsoft® Office Excel 2003.

Chapter 4

All modeling has been conducted with Microsoft® Office Excel 2003.

All charts have been developed with Microsoft® Office Powerpoint 2003 and Think-cell® 5.2. Microsoft® Office Word 2003 was used to compile the written document.