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CHALLENGES FOR INVESTMENT IN RENEWABLE ELECTRICITY IN THE EUROPEAN UNION

Background report in the ADMIRE REBUS project

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Abstract

This report serves as a background report of the main report of the ADMIRE REBUS project (see Uyterlinde et al. 2003). The report focuses on challenges that arise from changes in political support systems, lead time and risk with respect to investment in RES-E technologies. It discusses which tools and strategies that can be used in order to overcome these challenges.

The objective of this report is to elaborate further on the above-mentioned discussions compared to the main report. This is mainly done based on illustrative case studies with data taken from questionnaire analyses and data surveys.

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SUMMARY

This report serves as a background report of the main report of the ADMIRE REBUS project (see Uyterlinde et al. 2003). This report focuses on challenges that arise from change of political support systems, lead time and risk with respect to investment in RES-E technologies. It discusses which tools and strategies that can be used in order to overcome these challenges.

The objective of this report is to elaborate further on the above-mentioned discussions compared to the main report. This is mainly done based on illustrative case studies with data taken from questionnaire analyses and data surveys.

The report shows the large diversity between the current national support policies to RES-E. Not only support policies differ between the Member States within EU, also lead time and risk connected to investing in RES-E technologies varies. The report focuses on the main lead times and shows how much they vary between the different technologies and Member States. Some recommendations are given to how to cope with lead time and the transactions costs that are connected to it.

Also risk described by fluctuations in revenue from RES-E investments is discussed. There are many different kinds of risk factors. Therefore, it is not always easy to keep an overview. This report sets up two different frameworks for grouping Risk factors and that make it easier to get an overview. A quantitative study is described in order to show the relative importance of the different factors. The different risk factors’ interpretation varies between the technologies, support policies, and Member States. The risk discussion ends with recommendations on how to reduce risk.

European harmonisation of renewable electricity policy is under consideration, which means that current and potential investors find themselves in a transition period. This causes a lot of uncertainty. Still, regardless of whether harmonisation will eventually occur, experience indicates that foreign investors will have to face additional barriers compared to domestic ones. Therefore, the report ends with a brief discussion of the future trends in policies.

1. INTRODUCTION

During the last 30 years, renewable energy technologies have received political support within the EU. The motives, favoured policies and measures to promote the deployment of electricity from renewable energy sources (RES-E) have differed largely. After the oil crises renewable energy was seen as a long-term substitution to fossil fuels as exhaustible resources. Later, promotion of RES-E was supported as a mean for an EU-wide security of supply in order to strengthen the competitiveness of the European electricity supply industry. Another motive was increasing employment opportunities in areas with lower economic growth. Finally, in the light of climate changes RES-E is seen as a good alternative to thermal produced electricity that emits greenhouse gasses.

Due to this spread of policy goals also the support schemes differed widely within the different Member States and technologies. At present, no two Member States of the EU have common support schemes for RES-E.

However, the liberalisation of the energy markets and creation of a single market put a pressure on finding common support schemes. In addition, the technological development of renewable energy technologies makes the gradual introduction of market forces and the reaping of efficiency benefits relevant also for RES-E. Thus, renewable energy plants are established and operated at the lowest possible cost to the national economies. The long-term aim is to create more competitive mechanisms in the renewable energy market. This change of system will unavoidably alter the way investments and deployments of renewable energy technologies are made.

If renewable energy technologies have to compete with thermal based power without additional support, new investments may not take place and the change in the system will be difficult. Apart from the long-term contracts that have supported virtually all existing renewable energy projects, but which will be very rare in competitive markets, the market reality is that investors have very short investment horizons. In markets characterised by short-term energy sales and price volatility, investors will prefer technologies with short lead times, low transaction costs and risks. Funds for risky, capital-intensive renewable energy projects will be expensive and difficult to obtain, even if they are expected to produce more cost-effective power than fossil plants over their lifetimes.

These obstacles for investments in RES-E technologies in a competitive environment have to be taken into account when designing the new power markets and support schemes. In designing new market structures it has been suggested that environmental markets that run parallel to the physical power market should be created.

The most recent environmental market design in Europe is a market for tradable green certificates (TGC), where renewable energy producers receive an additional payment for their clean power under competitive conditions. The physical power is still sold in the power market where the prices are determined at short-term energy sale, but the price determination at the green certificate market is made according to long-term planning and might therefore be based on long-term perspectives. This should invite investors to invest in these renewable technologies and, thereby, ensure a politically planned spread of the use of renewable energy.

Although green certificate systems are sound in theory, there is currently a lot of uncertainty about how they will work out in practice. This is due to several factors like the lack of experience with such systems. In addition, it is unclear how green certificate systems will be implemented: if there will be different national systems where some countries do not introduce market based support systems, if there will be a common EU wide system or, finally, if some countries will make clusters of common systems. For investors, these uncertain factors lead to insecurity about the market size and the value of green electricity.

At present only a few Member States have decided to introduce a TGC system, many Member States continue with their present policies or introduce other kinds of policy system. Therefore, changes of support systems will continue to be considerable in the next decades.

In addition to the possible changes of support systems, the restructuring of the electricity sector radically changes the basis for investment decisions. For potential investors in electricity generation capacity the restructuring will shift focus away from security of supply and cost minimisation, towards profit maximisation. In a liberalised market investors care not only about the expected return on their investments, but also about fluctuations in revenue.

When potential investors turn their attention towards profit maximisation, a broad analysis of the economic viability of one or more investment projects gains in importance. In this regard a comprehensive understanding of factors influencing costs and revenues associated with those projects is essential. Cost factors that are directly connected to the projects are normally well known or procurable (e.g. investment costs for machinery, buildings, ground acquisition or overhead and maintenance costs). Although those figures are subject to uncertainties or risks investors are aware of their general impact on the profitability of an investment.

In addition to these cost components, investment projects are exposed to a further source of potential costs. Especially investors in RES-E encounter various administrative steps to be taken previous to the actual construction of a plant. This implies that an investor has to face several kinds of challenges when he is evaluating the opportunity to undertake a specific RES-E investment and the modalities of development of his project. He has to evaluate the time that will be needed before the first money comes in, the costs and risks he will incur. In the case of emerging markets such as the market of renewable energies, these challenges are especially acute, as the amount of available experience on which one can rely is not high.

In general the challenges lies within three elements of the investment:

- The *lead time* before the production can start - this determines *when* the revenues from the investment will start.
- The *transaction costs* incurred before the production can start.
- The *risk* described by fluctuations in revenue when the production is running.

This means that different lead times, transaction costs and risk connected to technologies, policy systems, or country based cultures create a complex set of challenges for investors in renewable energy.

This report focuses on these challenges and discusses which tools and strategies can be used in order to overcome them. The report works as a background report of the main report of the ADMIRE REBUS project (see Uyterlinde et al., 2003). The idea with this report is to elaborate further on the above-mentioned discussions compared to the main report.

As lead time and risk factors varies between technologies and Member States it would be too ambiguous to give a deeply quantitative description of all these factors. Instead a number of case studies will be used. For a matter of formal clarity regarding presentation graphs are used. The information for this is partly found be a questionnaire analysis that was done within the ADMIRE REBUS project.

This report starts with a short overview of EU legislation and different support policies for renewable energy. Chapter 3 gives overviews over the different challenges that an investor faces with respect to lead time when investing in renewable energy technologies. These are discussed with respect to tools and strategies of how to cope with it. Risk described by fluctuations in revenue is discussed in Chapter 4. Chapter 5 looks at the future and discusses trends in policies and emerging markets. Finally, Chapter 6 summarises the discussions and provides some final remarks.

1.1 Case studies and qualitative survey

In the following chapters lead time, transaction cost and risk is discussed. Besides the theoretical discussions it would be nice if we could present a survey of the different lead time, transaction costs and risk connected to investment in RES-E technologies within EU. However, as indicated in the section above, the various lead time, transaction costs and risk factors vary between technologies and Member States. Therefore, it would be too ambitious to give a deeply quantitative description of all these factors. Instead a number of case studies will be used. For a matter of formal clarity regarding presentation, graphs are used. The information for this is partly found in a questionnaire analysis that was done within the ADMIRE REBUS project.

The responses from this analysis are used, in order to get an appetiser of how the interpretation of the challenges is in different Member States with respect to investments in different renewable energy technologies. Thereby, the surveys and cases studies are qualitative[1] and not quantitative[2]. This means that the information that was received reflects trends and tendencies rather than exact figures.

The questionnaire had 61 respondents where especially wind power was represented well. The technology split is shown in Figure 1.1 below.

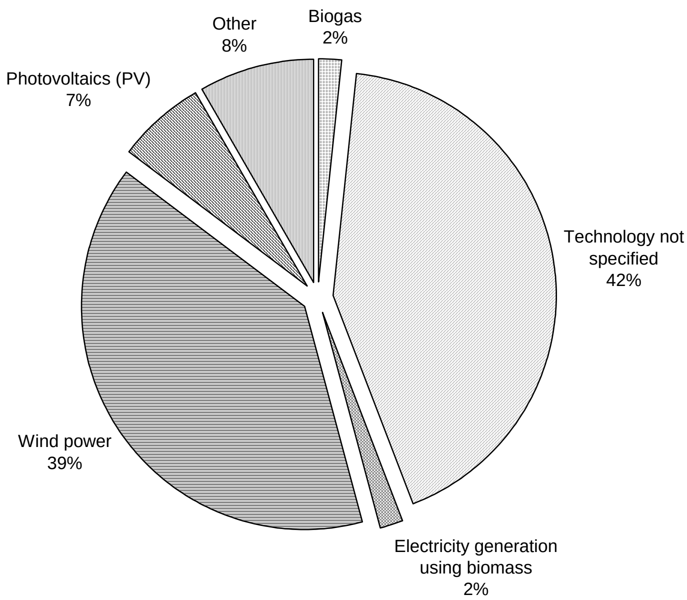

Figure 1.1 *Responses split per technology*

The responses represented 12 different Member States (Table 1.1). UK and France were the most represented countries.

[1] That is, one based on qualitative feedback from experts.
[2] That is, one based on a representative sample.

Table 1.1 *Responses split per countries*

Country	Responses
(Not specified)	22
Austria	1
Belgium	1
Denmark	6
France	13
Germany	1
Ireland	1
Italy	6
NL	2
Norway	1
Spain	1
Sweden	2
UK	14

2. RENEWABLE ENERGY SUPPORT POLICIES

2.1 EU legislation and RES-E targets

The Directive on the Promotion of Electricity produced from Renewable Energy Sources (RES-E) in the internal electricity market[3], is the main legislation affecting RES-E at EU level. This directive aims at facilitating a medium-term significant increase in RES-E within the EU. It must be considered in the context of the indicative objective of doubling the share of renewable energy from 6% (in 1997) to 12% (in 2010) of the *gross inland energy consumption*. This objective was set in the 1997 White Paper on renewable energy sources[4] and endorsed by the Energy Council in May 1998. The White Paper includes an Action Plan and a Take-off Campaign that sets some specific objectives and key actions per technology.

This 12% of gross energy consumption has been translated into a specific share for *consumption of RES-E* of 22,1% in 2010[5] from 14% in 1997. The Directive also establishes indicative targets for the penetration of RES-E in each Member State (see table below).

Table 2.1 *Indicative RES-E targets in 2010 (including large hydro)*

	Total electricity consumption[6] [GWh]	Target RES-E [%]	Target RES-E [GWh]
Austria	70,626	78.1	55,189
Belgium	105,151	6.0	6,309
Denmark	44,400	29.0	12,876
Finland	96,614	31.5	30,240
France	537,701	21.0	112,917
Germany	613,277	12.5	76,660
Greece	72,463	20.1	14,565
Ireland	33,800	13.2	4,462
Italy	359,018	25.0	89,755
Luxembourg	7,951	5.7	453
Netherlands	132,688	9.0	11,942
Portugal	62,037	39.0	24,194
Spain	255,614	29.4	75,151
Sweden	162,563	60.0	97,538
United Kingdom	500,342	10.0	50,034
European Union	*3,054,244*	*21.7*	*662,160*

3 Directive 2001/77/EC of September 27th 2001.
4 COM (97) 599.
5 The 22.1% of the Directive was based on a target setting in the first proposal of the Directive. In the adopted version, various countries had lower targets (e.g. NL has 9% instead of 12%), see also the many footnotes in the Directive. Therefore the realistic calculation achieves 21.7%. Note that in practice the resulting percentage will depend on the realised electricity consumption in 2010.
6 Sources: Renewables Directive and European Union Energy Outlook to 2020.

Taking account of the wide diversity of the present promotion schemes between Member States, the Directive states that it is too early to set a Community-wide framework regarding support schemes. Accordingly, the Directive establishes a kind of minimum framework for renewable energy policy development in the Member States[7]. It represents a start for harmonisation of Member State support schemes in the longer run. Therefore, there is no harmonisation yet, but the intention to consider it. For that reason, it would be more appropriate to regard this as a period of transition with a time schedule (for more on harmonisation see subsection 6).

In this context, of all the dates and milestones established in the Directive[8], the most important in the context of this report is the one set for October 27th 2005 at the latest. By then the Commission should present a report on the experience gained with the application and coexistence of different support schemes in the Member States. Based on the findings from the Commission the report may be accompanied by a proposal for a Community framework for RES support schemes. However, the directive also stipulates that such a proposal for a harmonised support framework should allow a transition period of at least 7 years (thereafter) in order to maintain investors' confidence and avoid stranded costs.

Thus, up to 2005, uncertainty about the development and amendments to national policies for new investments may grow. Furthermore, the Directive also sets requirements concerning the mandatory Guarantee of Origin. No later than October 27th 2003, Member States shall ensure that the origin of RES-E can be guaranteed as such according to objective, transparent and non-discriminatory criteria laid down by each MS. In this context, they will issue a guarantee of origin, which will contain data about the energy source from which the electricity was produced (including dates and places of production). The aim is to enable producers of RES-E to demonstrate that the electricity they sell is produced from RES. Guarantees of origin will be mutually recognised by MS.

Finally, the Directive states provisions that ensure third party grid access. It states that Member States shall take the necessary measures to ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of RES-E.

2.2 National renewable energy support policies

Today, the EU electricity market is characterised by institutional innovation and diversity. However, in spite of fiercer competition, electricity markets, and in particular renewable electricity investments businesses are still shaped by national idiosyncrasies. So far this has been a necessity, since different Member States in the European Union have different mixes of renewable electricity support mechanisms in place or in preparation.

Some of them are designed to stimulate the supply of renewable electricity, while others affect the demand. This classification can be combined with other which distinguishes between generation based and capacity based support schemes (see figure below).

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7 In the words of the Directive "(...) One important means to achieve the aim of this Directive is to guarantee the proper functioning of the (national) mechanisms, until a Community framework is put into operation, in order to maintain investor confidence" (number 14 of the Preamble). "It is too early to decide on a Community-wide framework regarding support schemes (...)" (number 15). "It is, however necessary to adapt, after a sufficient transitional period, support schemes to the developing internal electricity market (...)(number 16).

8 The Directive sets other specific deadlines obliging either MS or the Commission. Concerning the obligations on the former worth mentioning are the following: 1) Publication of reports setting national indicative targets for future consumption of RES-E for the next 10 years (deadline for 27 Oct 2002 and then ever five years). 2) Publication of national reports on success in meeting the national indicative targets (27 Oct 2003 and then every two years). 3) Issuing a guarantee of origin of RES-E (27 Oct 2003). 4) Publication of a report evaluating the authorisation procedures for RES-E plants (27 Oct 2003). Commission obligations are: 1) Publication of a report assessing if MS have made progress towards achieving their national indicative targets (27 Oct 2004 and then every two years). 2) Presentation (to the European Parliament and the Council) of a report on the implementation of the Directive (31 Dec 2005 and then every five years).

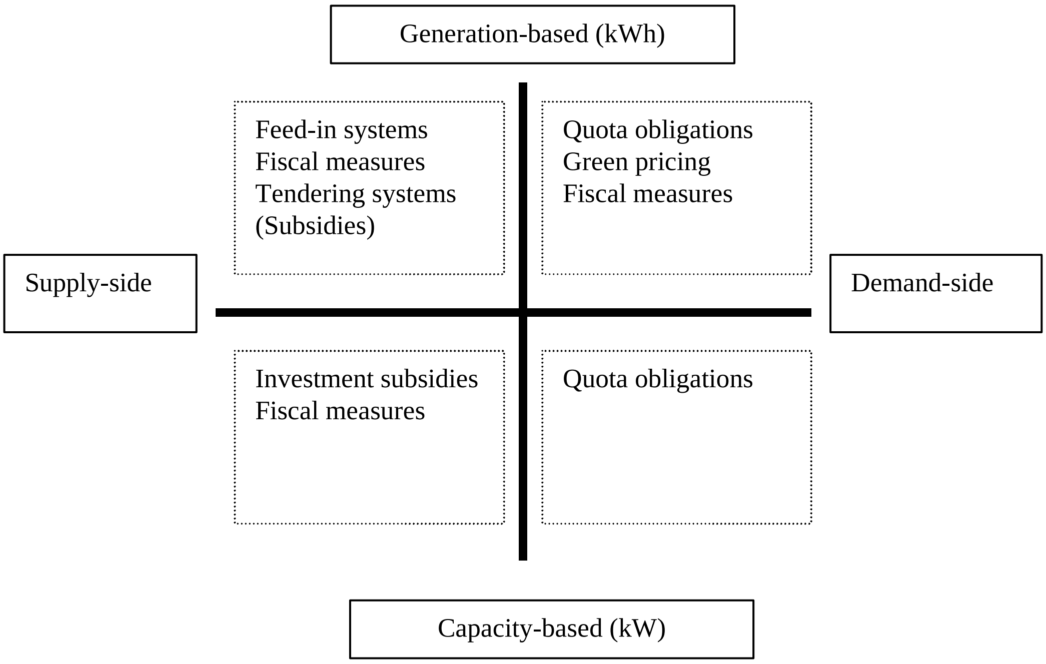

Figure 2.1 *Classifying RES-E Policy Support Mechanisms*

Some countries apply differing instruments for distinct technological options. Others propose two policy instruments for one technology, or several instruments depending on the size of the project. Some theoretical features of the main policy instruments are described in the next section.

It should be noted that not all promotion schemes have the same relevance for the promotion of RES-E. National promotion regimes are usually based on one of the following schemes (primary support measures): feed-in, TGCs, or, to a lesser extent, tendering/bidding systems. A second group of relevant but complementary support measures (secondary support measures) includes investment subsidies, fiscal and financial incentives. Countries usually have one (at most, two) of the schemes in the first group (except Finland that does not have any). This is supplemented by a combination of measures pertaining to the second group. Table 2.2 gives a brief schematic survey of the present and most important policy regimes implemented in each country within the EU. For further details the reader can turn to (Uyterlinde et al., 2003).

Table 2.2 *Survey of present and most important national RES-E promotion schemes*

Incentives / Country	Feed-in tariff	Investment subsidies	Fiscal incentives	Financial incentives	Quota obligations / TGC	Tendering systems	Green pricing
Austria	X	X	X	X			
Belgium	X	X	X		X		
Denmark	X	X	X				
Finland		X	X				X
France	X	X	X			X	
Germany	X	X		X			X
Greece	X	X	X	X			
Ireland						X	
Italy	X		X		X		
Luxembourg	X	X	X	X			
Netherlands	X	X	X	X			X
Portugal	X	X	X	X			
Spain	X	X		X			
Sweden	X	X			X		
United Kingdom		X	X		X	X	

2.2.1 Feed-in tariffs

Feed-in tariffs stimulate generators of RES-E to introduce electricity into the grid by receiving in exchange a minimum price per kWh produced, the feed-in tariff. As generation costs differ across renewable energy technologies, the feed-in tariff is usually different per technology and is provided for a specified period of time. The feed-in tariff can either be the only revenue the producers get, or it can be a supplement to the power price or other subsidies.

Policy making in the feed-in tariff case

Feed-in tariffs are set by the regulator. Currently bestowed premium prices are generally technology specific, and can vary significantly among EU countries. A major issue, therefore, is what are the criteria for setting them at either a lower or higher level. Part of this diversity is due to the fact that policy makers aim at spurring the domestic renewable electricity production towards a national target by setting a premium price.

Although, according to some authors, the feed-in should be designed to reflect the long-term marginal production costs (Haas et al., 2001), they are usually set at a level that also guarantees a 'reasonable profit' for the investor in order to stimulate investment. Therefore, security in investment is the main reason for using feed-in tariffs as a renewable energy promotion scheme. This is done by assuring investors' revenue.

In theory, by setting the price but not (directly) the quantity produced, it is not entirely certain a priori how much RES-E will be promoted. However, the facts tend to prove that the feed-in tariff instrument is indeed a very effective, but probably expensive instrument[9]. The following can clarify this.

When policy makers decide on the feed-in tariff level to achieve a certain quantity of production, three cases can occur.

1) Policy makers' estimation of the feed-in level is correct and has provided the optimal tariff equal to the marginal costs of deploying RES-E; exactly the national target has been reached. This is the optimal case (the use of tariff is effective and efficient), but it is very rare due to imperfect information of the actual, marginal cost.
2) Policy makers underestimate the marginal cost and set the tariff too low. Hardly any additional investments in renewable electricity technologies become viable. In this case, the total costs of the feed-in system are low, but the national target is not achieved. In this case, the use of tariff is cost-efficient but not effective.
3) Policy makers overestimate the marginal cost and set the tariff too high. Many investors will then enter the domestic renewable electricity market. Their success will depend on other than financial factors, such as administrative barriers; the national target might be readily achieved or exceeded. Since the tariff is set above the marginal cost, the total cost of the feed-in system will be higher than in the optimal case; society (consumers or taxpayers) pays for attaining this level of renewable electricity output. In this case, the use of tariff is effective but not cost-efficient.

Many policy makers perceive the important risk of underestimating or overestimating the feed-in tariff, and have been, therefore, searching for more efficient, market-oriented support instruments such as a TGC scheme.

[9] The cases of wind energy in Denmark, Germany and Spain show that in the past feed-in tariffs have led to significant increases in RES-E deployment.

2.2.2 Tradable green certificates

Green certificates is, first of all, a certification of the produced RES-E. This certification provides an accounting system to register production, authenticate the source of electricity, and verify whether demand has been met. When the certificates are tradable, they are denoted tradable green certificates (TGCs) or Tradable Renewable Electricity Certificates (TRECs). The main benefit of making them tradable is to facilitate trade and, thereby, stimulate deployment of renewable energy based technologies in the most efficient areas and countries, i.e. it provides a cost-effective means of achieving a target for generation or consumption of renewable electricity. Furthermore, the level of ambition of the target or obligation is reflected in the price of the TGC. This can provide a clear price signal to potential investors in renewable energy projects. Moreover, TGC trading stimulates competition between producers, which is expected to lead to declining costs of renewable electricity generation.

Thereby, the main idea of a market for TGCs is to ensure a (politically) planned deployment of renewable energy technologies as effectively as possible to maintain low consumer prices for power and enable efficient renewable energy burden sharing. In particular, the market for TGCs should make it desirable to invest in renewable energy technologies, and ensure that investments are made in the most effective technologies and locations.

Concerning the supply side, TGCs deal with energy that is actually produced and not merely available capacity, compared with other methods to promote the development and deployment of renewable energy. Each time a green power producer sells electricity to the grid, he receives a corresponding number of TGCs. These certificates are financial assets and tradable. In addition to the physical power market, they can be sold in an organised, financial market established for green certificates and thereby realise an additional payment to the producer for his green power. Therefore, the TGC market de facto functions with two markets. On the conventional, physical electricity market, renewable electricity producers sell their electricity to the market operator receiving in exchange the wholesale electricity market price. On the financial TGC market, the ‘greenness’ can be traded separately from the physical commodity. As a result of this, the price obtainable to the producer for the renewable-energy-based electricity will be the sum of the market-based settling price for physical power and the price of the TGCs.

Demand for TGCs is created, mainly, by imposing an obligatory quota on different actors[10]. Such a quota obligation is sometimes referred to as a Renewable Portfolio Share (RPS). The quota system itself does not include financial support directly, but it has an implied similar effect by spurring a domestic demand for certificates. According to national or international (e.g. EU) energy policies, every consumer or distribution company[11] is obliged to acquire at least a certain number of TGCs. This corresponds to a percentage of their yearly consumption. Thus, in the long term, this creates a financial market for green certificates via their demand for certificates. A penalty (price) may be introduced in order to ensure that the demand obligation is fulfilled.

The demand will subsequently contribute to the development of renewable-energy-based electricity production as the obligation (green quota) to acquire green certificates increases yearly according to the energy plans, e.g. the EU goal of 12% of renewable energy by 2010.

By letting demand for TGCs follow long-term goals and annual demand, the price setting differs from the price setting at the physical power market that is based at short-term sale and demand. By allowing the price setting of TGCs to be based at long-term perspective[12], this market design

[10] The Netherlands has a mixed system; on the production side it is like a feed-in tariff, but the demand is created by a tax-reduction for consumers that buy RES-E, and a TGC-system facilitates trade.

[11] In Italy, the obligation is on the producers.

[12] With the price determination at the green certificate market made according to long-term planning and perspectives the investor is able to obtain his long-term cost even though the power is sold at short-term cost at the physical power market.

is ideal for investment and deployment in RES-E where the demand for investment follows the increase in the green quota.

Competition between the producers of green power on the TGC market ensures that the supply price for TGCs reflects the actual price differential between 'green' and 'grey' power. Thereby, the market for TGCs has the important goal of giving key policy makers, industrial stakeholders, and consumers a price signal from the actual marginal renewable energy technology on the market.

Since the TGC market is independent of physical restrictions, e.g. transmission capacity, the TGC market allows for trade between countries and thereby represents different ways of burden sharing. Countries can lower their overall costs of meeting the targets by importing certificates instead of realising (a part of) their domestic target, or (in case of abundant relatively cheap RES-E potentials) export certificates.

The TGC system is a new market mechanism and only few experiences with this system exist. Therefore, although green certificate systems are sound in theory, there is still a lot of uncertainty about how they will work out in practice and about the actual design of the systems that will be implemented in certain countries. In addition, there is also uncertainty about how these systems will interact on an international, EU-wide level (Jensen and Skytte 2002, 2003).

Policy making in the TGC case

The main difference between the feed-in tariff system and the TGC system concerns the introduction of competition on both the renewable electricity market and the 'grey' electricity market. Implementation of a TGC system affects the amount of investor transaction costs. With respect to search and negotiation costs, for instance, the main difference is that under feed-in systems, renewable electricity producers do not have to find customers for their product on the market, only the grid and supply companies.

Other things being fixed, the price of the green certificate increases when a quota obligation is increased, and when production sites become more expensive. But the price of the green certificate decreases when technological improvement occurs. This dynamic effect is important to consider because the indirect goal of any chosen support scheme should be to place a technological option in the market. It is important to note that in contrast to what happened in the feed-in case, the price here is not fixed but always determined by the market. It will moreover be closer to the competitive price of new deployment. This reduces the overall cost of attaining a national target.

2.2.3 Other support schemes / instruments

Apart from feed-in tariffs and TGCs, other instruments have also been used in Europe to directly influence the demand or supply of RES-E. In this section, a brief overview is given of the policy making involved in these instruments from the investor point of view.

Tendering procedures

In this system, a public institution invites generators to compete (through tenders) for a specific financial budget or capacity. There are usually separate tenders for different RE technologies and technology bands. Within each band contracts (and the corresponding support) is awarded to the cheapest bids. These procedures, which stimulates strong competition between RES-E generators and hence cost-efficiency and price reduction, have not shown great success in promoting RES-E probably due to the complexity of the procedures involved in a tendering system.

However, once bids are awarded they usually work as a feed-in scheme giving a good deal of certainty to successful bidders[13].

Investment subsidies

RES-E plants are often capital intensive projects with relatively low running costs. Therefore, governments may offer subsidies on investment for RES-E technologies in terms of €/m^2, €/kWh or percentage on total investment (%). Investment subsidies shift the marginal cost curve of the subsidised technologies, making them competitive at market prices. Support can be modulated per type of technology, size and geographical location of the installation. They are the oldest, and still the most common type of schemes. This may be explained by the fact that it probably is the most feasible political way to introduce non-competitive technologies into the market. However, a major disadvantage of this instrument is that it gives no incentive to operate the plant as efficiently as possible (Schaeffer et al., 2000; Haas et al., 2001)[14].

Fiscal incentives

A wide array of incentives can be grouped in this category. Among them: exemption of RES-E from energy taxes, tax refund for RES, lower VAT rates for RES-E, exemption of investments in RES-E plants from income or corporate taxes etc. They all increase the competitiveness of RES-E and may affect old and recent installations (generation-based incentives) or only the new ones (capacity-based incentives).

Fiscal and financial incentives are very widespread, probably because they are usually easy to implement given that fiscal structures are already present in all countries. However, it is important to note that they usually represent secondary promotion measures. For instance in countries with quota obligations, fiscal incentives are usually put in place to stimulate demand. One additional disadvantage is that they can be quite inefficient (especially those which focus on new capacity).

Green Pricing

In these systems a surplus on the electricity bill is voluntarily paid by consumers to promote RES-E. This surplus, which is paid to suppliers, finally goes to generators to cover the additional generation costs of renewable electricity. Obviously, this system depends on the willingness to pay (WTP) for renewable electricity on the part of consumers, which differs from country to country. Such WTP is influenced by factors related to consumer environmental awareness and specific market conditions (degree of market opening) (Haas et al., 2001). From the point of view of the investor, it should be noted that these systems might lead to a reduced and uncertain demand. This is partly due to the lack of confidence on the part of the consumer, which may be sceptical about the surplus paid going effectively to the promotion of renewables. Nonetheless, further investigations that provide insights on the performance of these schemes should be undertaken.

[13] According to Haas (2001) a further disadvantage is that administration costs are high, at least higher than in the case of feed-in schemes.

[14] A scheme of gradually decreasing investment subsidies might be given to potential investors in order to discourage delays in investments due to expected price decreases of the technology (Schaeffer et al., 2000). Subsidy programmes may also lead to further delays in investments, as they usually require the applicant to wait for the approval of the subsidy before beginning to install the plant (op.cit.). Finally, and apart from the problem of ‘windfall gains’, an investment subsidy does not prevent the subsidised generator from stopping production in the near future.

3. LEAD TIMES IN THE PLANNING AND CONSTRUCTION PHASES FOR RENEWABLE ELECTRICITY PROJECTS

3.1 What is lead time?

An investment project can be divided into several phases:
1. the planning phase,
2. the construction and commissioning phase,
3. the production phase.

Revenue is generated only in the production phase. The first two phases don't generate revenue; on the contrary they bring about many costs and uncertainties. These costs and uncertainties have to be taken into account in the evaluation of the investment by the investor. More or less time can pass between the investor's first moves about a project and the start of the production phase. The investors have many different steps to undertake between the moment they become interested in a site and the moment their production unit is finally working and bringing in the first flow of money.

In order to evaluate their investment correctly, they need to be able to estimate the time and costs the first two phases take. This can be done quite easily regarding the construction and commissioning phase - and we will elaborate on this issue below. The time required for construction depends on factors that do not vary a lot: the availability of material, and of technical staff. There is little uncertainty. On the contrary, evaluating the costs and length of the planning phase is much more difficult.

In the planning phase, the costs are the costs of man-days that are required to carry out the project and will be taken into consideration as transaction costs. This section focuses on the *length* of the planning phase. The following presentation is a global pattern of the planning phase that can count more or less steps in some cases and in which the order of some steps can change, but it roughly represents what investors have to go through for most of the technologies and countries.

The planning phase can be divided into three main periods:
- Pre-feasibility phase:
  - First enquiries about a site
  - Check-out for land constraints
  - Measurement campaigns
- Development phase:
  - Technical and financial study
  - Environmental impact and public enquiry
- Administrative approval
  - Construction permit
  - Connection to the grid

The time-lag that is needed to carry out a project from the first moves made about a site till the moment the electricity sales starts is referred to as 'lead time'. The problem for investors is that lead times can vary a lot from one country to the other, but also within a country from one region to the other and even often from one project to the other.

Two kinds of lead times can be discerned:
- techno-economic lead times
- administrative lead times.

Techno-economic lead times are linked to the pre-feasibility phase, and to the development phase. The pre-feasibility phase is a prerequisite to the setting up of the project's technical and financial documents and to the investment decision. First, the investor has to locate a site that is of interest. The time needed for this mainly depends on his own time schedule. This time is quite diluted as the task to look for a site is often mixed while carrying out other activities. There is then a first eye check of the place, where the investor can judge if there are no obvious impediments on the site (e.g. the presence of some monuments for wind projects or the physical disposition of a river). The check out of land constraints depends on the investor only: he has to verify that the land is free of constraints and available for his project. This verification consists of consulting some administrative files (that might already be available for other building projects) and does not require permission from the authorities. A measurement of the resources has to be carried out. For a given technology, this usually takes the same time in all Member States. It can of course be very different from one technology to the other. This phase is a purely technical one; its length is usually easy to evaluate and does not vary a lot. All of these tasks depend on the investor himself and are therefore quite easy to speculate upon. The same goes for the technical and financial study. This is a part that the investors often know well and are used to carry out.

Things are different when one comes to the administrative lead times. The investor has to obtain the authorisation to go ahead with his project in three different sectors of the Law:
- Energy Law: permit to exploit, connection to the grid, sometimes a contract with the national electricity company (in case of a feed-in tariff).
- Land Law: building permit.
- Environmental Law: rivers, landscapes, emissions, forests, etc.

Usually, these regulations are supervised by different administrations, which multiplies the number of interlocutors, forms and attachments. The investor has to wait for decisions from these administrations. And the greatest problem they encounter is that often these administrations have, for various reasons, longer delays than those that are planned in theory. The reasons for that will be detailed when reviewing the different technologies, but one constant is that the permits are given by local authorities which are very much linked to local life and sensitive to local influences and pressure groups.

Moreover, although the European Commission has set targets to achieve in terms of developing renewable energies, for the moment, member states are free to promote renewable energies according to a national policy (see Chapter 2 in this report). Hence, administrative procedures and attitudes of the administrations vary a lot among Member States. In case of investments abroad, the investor has to learn how to deal with other policy and administrative regimes and other lead times.

3.2 Lead times for wind power

The different steps of the planning phase for wind power onshore

During the pre-feasibility study, the investor has to make a site check visit. He screens on the spot to see if there are no major barriers to the use of the given site. For example, he will look for the presence of remarkable sites next to the chosen field and will evaluate the distance to the closest houses. The first enquiries also need to assess the distance to the grid, the presence of strong local associations (have they already opposed some building project?) and the presence of obstacles to the propagation of the wind. If the site appears to be a potentially sensitive issue, then it is very likely to be dropped at this stage. If the site passes this first screening, then it should be checked if it is free of constraints. Here the investor has to check if there are no civil, military, environmental constraints that apply to the site. For example, if the site is situated in a bird migration corridor or on an area reserved for the preservation of nature, it should be avoided. The investor also has to make the first contacts with the owner of the land to obtain his agreement. The pre-feasibility phase for wind power ends up with a campaign of measurement of the wind onsite, which generally lasts around a year. It requires the instalment of measurement masts.

A project in wind energy has to satisfy the three regulations mentioned earlier (Land laws, Energy laws, Environmental laws). In all Member States, the investor has to get a building permit, which has to be granted according to the country spatial planning regulation. Among the documents and requirements needed, the measurement of the project environmental impact is a crucial one. This environmental impact assessment (EIA) comes from the European Directive 85/337/CEE of 27 June 1985 and deals with the assessment of the environmental impact of some public and private projects. The categorisation of RES projects concerned by this EIA is left to the appreciation of Member States. It has to analyse what effects the project will have on the physical and natural environment as well as its socio-economic consequences. Applied to wind power, it includes generally estimation of noise, of shadow effects of wind turbines, of visual impact. The amount of work needed by this evaluation varies according to the countries and the size of the project. It can take the form of a short study (in France for small projects only a note on environmental impact is needed) or in-depth study made by an expert consultancy. There are various thresholds among the countries above which an Environmental Impact Assessment is needed. In Denmark, it is more than 3 wind turbines or if the wind turbine is more than 80m high; in the UK, it is more than 2 turbines, in the Netherlands more than 12 turbines or 10MW, in Germany it is more than 20 turbines, in Spain over 20 turbines, in Ireland over 5 turbines or 5 MW and in Luxembourg and Belgium over 1MW. In France the threshold is financial (over 1,8 Million €).

The application for a building permit can also lead to a public enquiry. This is not mandatory in all countries. In France it is now for projects over 10 or 25 hectares depending on the areas. In Italy it is not but will be in the next year or so. In all countries where there is an EIA, the project has to be made public and people can react. In Germany, the authorities have the obligation to inform the public and associations. Neighbours can be consulted after the application by the developer. In Denmark there is a public hearing during the instruction of the permit. An investor has also to ask for his connection to the grid. Finally, it is necessary to obtain an authorisation to exploit the production device.

In Luxembourg, there is an obligation in case of a competition of several projects for the same site that the different actors shall co-operate in order to build a common wind farm.

The length of the planning phase in wind power onshore

According to our qualitative survey, this is the distribution of the average planning phase for wind power projects onshore.

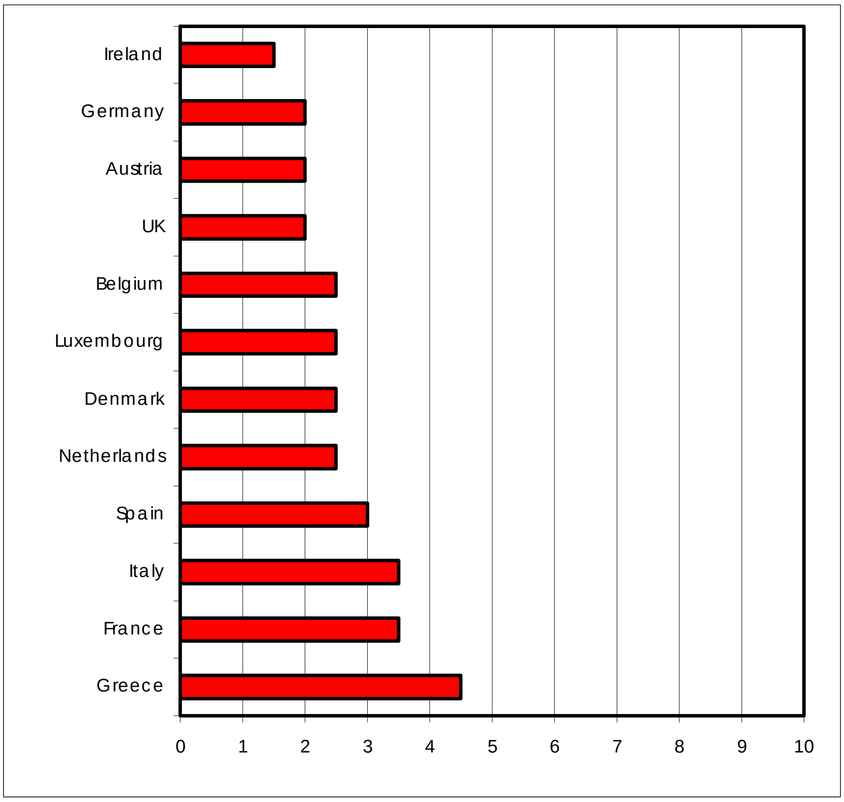

Figure 3.1 *Overall average planning time (wind power) in years*

Average lead times for the planning phase in Europe are situated between 1.5 years and 4.5 years. Southern countries tend to have longer lead times than others.

If we have a look at the extreme lead times that were experienced, we get the following picture:

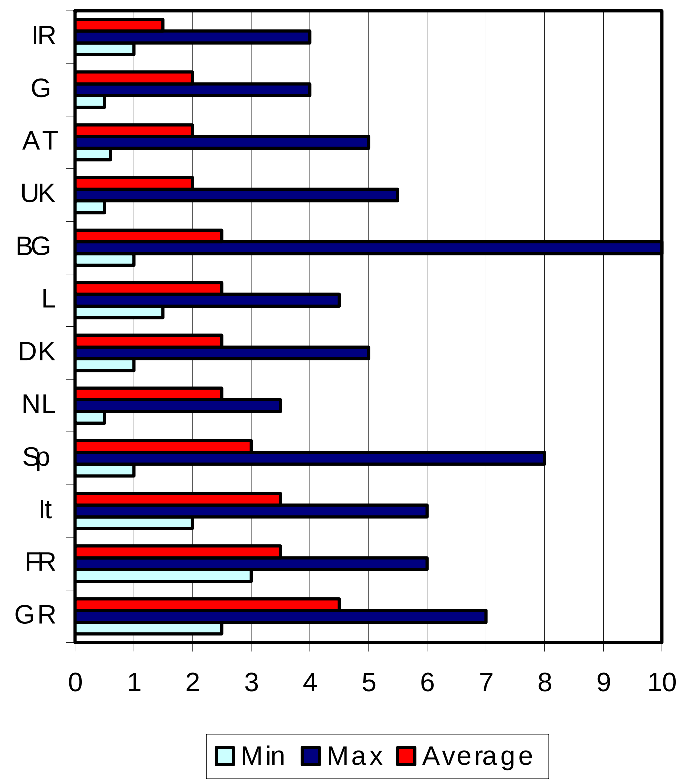

Figure 3.2 *Overall planning time extremes (wind power) in years*

In almost all countries, the maximum lead time is on the order of twice the average lead time needed. This leads to uncertainty about the actual length of the lead time. There are some countries where the maximum lead time lasts more than 5 years (Belgium, Spain, France, UK, Italy). However, if one compares the ranking of the European countries in terms of dynamism[15] with the level of uncertainty that is shown here, one can notice that a high level of uncertainty in administrative procedures does not prevent investors from undertaking new projects in wind power. Indeed, Member States which have a high feed-in tariff for wind power can have a dynamic wind power deployment even with large maximum lead times, e.g. Italy and Spain.

In addition, there can be difference between lead times experienced in the different regions of the same country. That is the case in the UK: in Wales, the planning phase goes up to 3 years, while in Scotland it is 1.5 years. England lies somewhere between the two. This is also the case in Spain, as authorisations for construction are given by regional governments and no single uniform criteria exist across them (therefore, 17 different approval procedures).

Problems that can cause delays

There are several causes of delays in the course of a wind power investment project. The two main reasons for extended and uncertain lead times lie with administrative procedures and local opposition.

One of the principal administrative causes of delay is linked to *spatial planning*. The necessity to be coherent with the country spatial planning often brings about the necessity to revise local plans (which explain the possible use of land in municipalities). Indeed, in several countries, the local plan does not include wind turbines. Hence they have to be reviewed at a local level when a project appears. This procedure is usually quite long. It happens in some municipalities in France (PLU), in Denmark, in the Netherlands (Bestemmingsplan), in Luxemburg (Plan d'Aménagement de la Commune). In the UK, in some regions there are guidelines for local authorities regarding the planning, but not in all. There are no such problems in countries where there exists an atlas for wind power projects, which identifies specific available sites (Germany, Belgium and Denmark to some extent).

In the UK, in addition to this problem there are some tensions with the Ministry of Defense, which opposes more than 25% of the proposals. The British authorities say that turbines create a vertical obstruction either to aircraft taking off or those involved in low flying training. However, in this context, the UK seems to be an exception. A study by Stasys (UK consultants) reveals that in Denmark, Germany, the Netherlands and Sweden, the military and civil aviation authorities are not so concerned about the presence of turbines. In fact, in Denmark the first offshore wind park was built less than two kilometres from Copenhagen airport.

Co-ordination between administrations

The ADMIRE REBUS workshops showed that in Southern Europe, the influence of incompatible administrative barriers seems important, such as the lack of inter-administrative co-ordination between different government levels. In Italy, at least three government levels are involved in the permitting process, i.e. Energy authority, Ministry, local government, regions, and province.

As there are three regulations to obey, there are many administrative windows to go to, hence many documents to provide. This is even worsened by the fact that some authorities require many complementary documents (Italy, France, Ireland for example) and decide on not transparent criteria (Spain) to grant the permit or not. In Southern Europe project developments have needed as much as 20 approvals. Particularly in Italy, procedures are said to be inefficient. Cross-authorisation means that different authorities wait for approvals from other authorities

[15] Cf. growth rates in the EurObserv'ER barometer

and reciprocally. For foreign investors in Italy, it can be expected that the permitting process to be even more difficult, because the process of obtaining licenses and approval depend partly on personal relationships. Investors who are based in a community for a long time may be favoured because they create jobs, or are even part of local government.

These purely administrative complexities are more acute in countries where regions have a lot of autonomy as in Spain (17 autonomous communities, CCAA, which all have different patterns to follow and where delays vary widely between them) or in the UK. This means longer time spent by the investor to find out what procedures he has to follow. However, in Spain the consequences have not been that dramatic. Since 1992, the growth rate in for example wind energy has been tremendous, thanks to investments made both at central and local levels. Spanish utilities, regional institutions involved in local development, municipalities, and private investors, and in some cases Spanish turbine manufacturers, have formed large consortia developing wind farms. Still, Spanish actors confirm that administrative issues increasingly become a large barrier in Spain.

Grid connection and grid strengthening can at once become the largest administrative barrier. In France wind farms are often located in areas where there are not many inhabitants and where the grid capacity is small. A complicated process of queuing has been created for projects, which has led some developers to put fake projects in advance in the queue in order to secure a place. The French wind case shows that a country with an excellent distribution system may perform poorly to collect MW of electricity depending on the wishes of all investors who tend to choose their sites on the basis of fuel availability only. However, different French administrations now try to co-operate and solve this responsibility and cost issue.

In contrast, Denmark, a Member State with a very different electricity distribution system, does not seem to suffer from such high administrative burdens. The main reason can be that the whole electricity system has historically been founded on decentral options like small cogeneration installations. Moreover, Danish transmission of electricity and distribution typically has been in public hands, which may prevent similar discrimination.

By creation of a liberalised, single power market within EU, the system operators are getting status as natural monopolies that shall give third party access to all producers.

Local resistance to alleged impacts

In north-western Europe, it is local resistance that causes main delays in licensing procedures. People can resist installations of renewable electricity plants because they claim visual impacts, or noise, etc. North-western administrations usually have much room to handle the claims and carry out appropriate procedures. The NIMBY[16] syndrome has some weight on the planning phase as procedures, even when a public hearing is not mandatory, generally leave some space for reaction of the public. In Denmark a project can be brought in front of a public tribunal up to several times and each round of this procedure takes around 0.5 year. The situation is similar in the Netherlands where citizens can appeal against the Environmental Management Act permit as well as against the building permit. In the UK, the possibility to oppose the projects lead to a governmental investigation, which can bring the length of the planning phase up to 8 years. In France and Spain (especially for wind onshore), local opposition can also be very important. The case of France is somewhat special because the current French wind experiences show that French administrations were not well prepared to play a role in this.

In addition to these delays, the issue of finally succeeding in getting the permit is another source of uncertainty.

[16] The Not In My Backyard (NIMBY) syndrome reflects the tendency of people to agree in principle to some projects that they don't want realised if they concern them in practice.

The EOLE case
A specific French experience is elaborated here because it shows how the process to obtain construction permits is more important for investments (here, in wind power) than ever thought before. The situation is about the same in other countries, and is moreover quite similar to small hydro project development.

By the end of 2001, France had no more than 94 MW wind power installed and the EOLE-2005 program, which had set a target of 500 MW for 2005 was heading for a fiasco. The EOLE tender contracts had resulted in prices of roughly 4.5 cents €/kWh, which appear to be one of the lowest granted to wind energy in Southern Europe at that time. In first instance, the causes of the financial problems met by the involved investors were not evident. With hindsight, they were often situated at the administrative front. Lead times and administrative burdens, much higher than expected, had rendered the proposed projects unprofitable. As the investors could not renegotiate the prices formerly contracted through the tender procedures, the results of EOLE are indeed very poor. Five years after the start of EOLE-2005, only 10% of the generation contracted with EdF was effectively produced.

What has been learned from the EOLE case?
In 2001, France boosted its wind target to 5,000 MW by 2010 and introduced the longed-for renewable energy feed-in tariff. The new wind program is indeed currently providing a new strong impetus to the development of French wind energy. Given the large number of MW claimed for the next decade, forecasts of 12,000 MW by 2010 are given by the French wind energy branch. At the same time, an increasing number of voices point to the hot issue of virtual wind energy. They know that obtaining the linked site-planning approvals is much more difficult than claiming these projects. In principle, the recently adopted feed-in pricing system covers more costs than merely plant costs. And with the increased guaranteed revenue, developers might put more effort in tackling the other, administrative issues. However, policy decisions regarding land and urban planning remain a barrier to wind power deployment in France.

Additionally, there are echoes about the grid issue. It is not clear yet who is responsible for grid connection costs, and for grid strengthening costs. In the meantime, current lead times are increasing. One can expect the potential investors to get rid of them for example by minimising the distance of new installations from existing connections. The issue is crucial mainly because the best wind sites in terms of resources are often the most expensive ones for grid connection and strengthening. Notice that many governments encounter problems around the allocation of grid connection costs, and that this issue has been addressed in the RES Directive.

Due to the described administrative barriers, the estimations for the French wind energy branch might well turn out to be an overestimation both of the MW target and of the speed at which these MW can be installed.

Construction phase
Regarding wind power onshore, construction delays are less than a year in all Member States. For two thirds of them it takes less than a half year. From this survey we can infer that construction time does not represent a specific problem regarding lead time. It is usually well known and estimated by investors. However, construction time varies according to size of the projects.

Offshore wind power projects
Regarding administrative procedures, there are additional requirements for offshore wind farms which are linked with maritime laws (offshore concessions in order to avert dangers to the safety and smoothness of the traffic and to the maritime environment) and authorisation of farm-to-shore cable for connection to the grid. An Environment Impact Assessment is required by all countries. Construction time is longer because offshore wind farms require specific and

complex foundations. On the whole, offshore projects can be estimated to last two years more than on-shore projects.

The case of Denmark

Different steps in the planning phase:

- Finding a site (available offshore wind turbine areas have already been identified in a government plan, but it is also possible to find sites outsides these selected offshore wind power areas).
- Technical and financial investigations (feasibility study). This involves obtaining preliminary prices for the different parts of the project, and estimating the wind resource at the site, which in some cases involves wind speed measurements.
- Gathering investors and negotiating with banks.
- Apply for building approval from the Danish Energy Authority (DEA). DEA either issues an Approval in principle or requires changes in the project.
- When the approval in principle has been achieved an Environmental Impact Assessment (EIA) must be carried out. This includes a public hearing where parties influenced by the project have a chance to express their opinions about the project.
- Final approval by the DEA.
- Tendering phase: involving prequalification of tenderers, making tender specifications, the tendering phase and finally the negotiation of the contracts.

Denmark is considering using a tendering procedure when new large (100 MW and above) offshore wind parks are going to be built. The wind parks will be situated in 5 areas that have already been pointed out. The Danish Energy Authority has released a report analysing how such a tendering procedure should be organised (see www.ens.dk the report is only in Danish).

According to the report the planning phase, i.e. the time period from the publication of the tender in EU to the detailed projecting starts, will be at least 2 years, and the building phase, i.e. from the start of the detailed projecting to the power delivery from the wind park starts, will be 2 years. An Environmental Impact Assessment will be have to be made in the planning phase and paid for by the winners of the tendering procedure.

Length of planning phase: 3 years / construction lasts 1 or 2 years.

Problems that can cause delay

They are of the same nature as for wind onshore, meaning conflicts with local actors on environmental impact (bird migration), visual impact, impact on fishing industry. Several countries (UK, France) plan on making call for tenders for offshore projects in order to fulfil European objectives in terms of installed wind power capacities. This can mean less difficulties to obtain permits and authorisations in the future.

3.3 Lead times for small hydropower

The different steps of the planning phase for small hydropower (SHP) projects

The pre-feasibility phase starts with a preliminary measurement campaign of the hydrology of the river (relevant physical parameter of the flow are discharge, head, lowest water level, highest water level, reserved flow...). Once the investor has an idea about the site in which he wants to build the plant, he has to undertake the same kind of eye check than for wind power relatively to the environment of the site: proximity to grid, to remarkable sites, disposition of the river, possibility to merge the plant in the setting... Often the investor gets an idea of the type of impact the plant will have on the environment at this stage. Some rough measurement can be done at this time also. The investor makes a pre-calculation of costs and return of investment.

The first contacts with landowners are done early in the project. Then the investor has to make a first check of the obligations that lay on the land. At the same time he has to check the obligations on the water: specific rights, environmental constraints... A legal agreement then has to be reached to secure the project with the landowners before asking for the different permits. As will be shown later, the process for being granted those permits can be quite a lengthy one and landowners have time to change their minds.

The legal conditions for building a new SHP plant or for recovering an old one are similar in most countries:

- water use or abstraction
- building permit.

The water abstraction allows the producer to exploit a natural resource that is a property of the state. In most of the EU Member States, with the exception of Sweden, Finland and Ireland, the principle of public ownership of water applies. The permits for water abstraction are issued by regional or local administrations. The law foresees the maintenance of a reserved flow level in order to preserve animal and vegetal life in the river. If the reserved flow is not specified in a legal text, then it is in the license. This license is granted only for a definite period of time in all countries. It lasts at least 10 years and can go up to 90 years. The length is meant for the investor to have an acceptable rate of return.

The building permit is the authorisation to build the plant in itself. When a right to use water has to be granted, the building permit is usually subordinated to the obtaining of the water license. In some countries, the water license is conditioned to the obtaining of an environmental permit or requires at least that environmental impact has been assessed. The authorities then grant the license after having considered among other things the conclusions of the EIA. The consultation of the local planning specifications is done with the water licensing procedure if there is one or with the building permit if there is none. The table below surveys the different procedures for Small Hydro Power.

Table 3.1 *Different procedures for hydropower plants in the different Member States*

Country	*Environmental impact assessment*	*Water permit*	*Building permit*	*Specifications for participation of the public*
Austria	No permission from the nature conservation authority is necessary	Preliminary authorisation procedure states doubts concerning the project. Process is administered by district administration authorities. Maximum duration of license: 90 years	Municipalities	Oral hearing
Belgium	Yes, the environmental permit	Ancient water rights are still legal (on non-navigable rivers) and are linked to ownership rights. For new rights, need to address the Direction de l'environnement et des ressources naturelles (Wallonie) or Department Leefmilieu en Infrastruktuur (Flamish region)	Permit of urbanism from communal authorities. Time limit is set by the norms	Public enquiry

Country	*Environmental impact assessment*	*Water permit*	*Building permit*	*Specifications for participation of the public*
Denmark	Almost no potential			
UK	Depending on the project	Abstractions over 20 m^3/day must be licensed. Applications must be made to the National Rivers Authority. It is issued for at least 15 years	Planning permission is asked from District Council	Public consultation: information on project is provided in public places
Finland	Environmental Permit since the Environmental Protection Act (March 2000). Is given by one of the 13 regional environment center	No water rights	Checking against the list of banned waterways from law	Intention to make the public participate from the start of a project
France	Yes, for units >500 kW. For smaller units only an Environmental Impact Leaflet	A lighter procedure for units <4.5MW (authorization as opposed to concession for units <4.5MW) Decision by the departmental head of administration (Prefet) for authorization license and by the ministry for concession license. License lasts 30 years	Building permit accorded by head of department authority	Public enquiry
Germany	Dependent on the projects	Authorized by the Länder, authorization has a validity of 30 years. Almost no new hydropower scheme, but only rehabilitation of existing plants	Yes also given by the Länder	Public must be informed in case of an EIA by publication in national newspapers
Greece	Preliminary environmental impact assessment and evaluation replaces pre-siting permit	Authorised for 10 years Details of procedure in Law 2941 of 2001	Approval of intervention on Public Land (Regional government, Regional Forestry department)	Participates in the Preliminary environmental impact assessment
Ireland	For projects listed in the EIA Regulations (Statutory instruments n° 93 of 1999). In 1989, it was required for plants over 20 MW. Others require an environmental impact study	The rights are linked to the ownerships of the land that gives access to the water	Planning permission is to be asked from the local authority manager or delegated officials Some deadlines are given for decision: 2 months. Then an appeal is possible during 1 month. A case can be decided in 4 month time	Participation of the public is required in case of EIA
Italy		Yes, granted for a maximum of 30 years	Yes, five permits required before getting the authorisation	Public enquiry is not mandatory now but will be in the next year

Country	*Environmental impact assessment*	*Water permit*	*Building permit*	*Specifications for participation of the public*
Luxembourg	Yes, to be validated by the ministry of environment	Reactivation of ancient Water rights. Almost all potential is used up	Town authorities	?
Netherlands	Yes, the Environment Management Act permit, from the municipality No building nor water use permit before EMA permit	Yes. Existence of specific hydropower plans	Yes	In the EMA permit
Portugal	Yes. Procedures are given in Decree-Law n°69/2000, Despachos n°11091/2001, n°12006/2001, n°583/2001	Water licenses are given for 35 years for hydroplants below 10MW. Portaria n°445/88 specifies information to submit. The regional authorities have 120 days to state over a demand	To be granted within 30 days after the water license	
Spain	Yes Formalities to be carried out through the Basin Board of the territory	Water Act (29/1985): concession is granted for a maximum of 75 years, according to the provisions of Hydrological Plans. Abbreviated formalities for plants under 5MW (one year would be necessary if the terms of the procedures were respected, 2 or 3 years are necessary for all the formalities)	Yes	Project is published in the Official Gazette of the Province allowing 20 days for objections
Sweden	Yes, the MBK	No	No further plans to exploit large rivers in Sweden. Possible to start old plants again. Rights granted according to the chapter 4 of the Environment Code which bans partially or totally some rivers. The investor has to have 50% of the rights of the land	Consultation of people that could be affected by the project (Chapter 6 of environment code)

The length of the planning phase for small hydropower plants

According to our qualitative survey, this is the distribution of the average planning time:

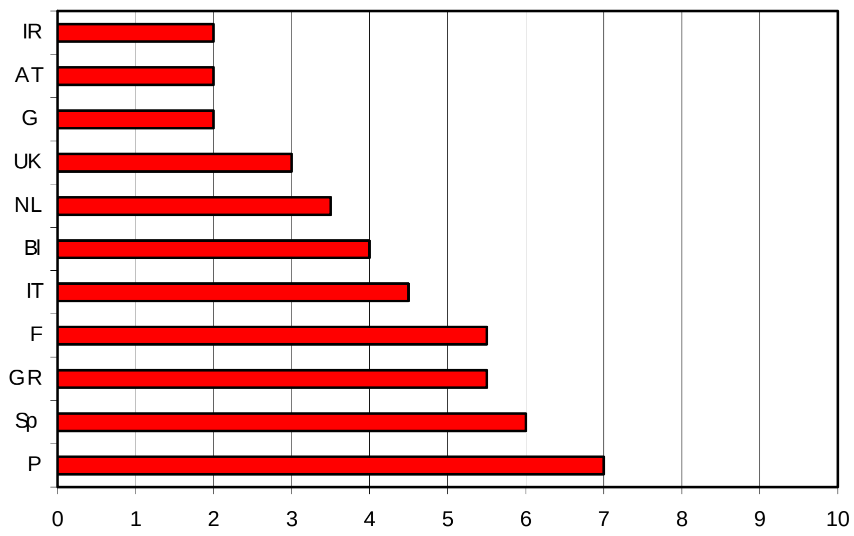

Figure 3.3 *Overall average planning time for SHP in years*

SHP projects have much longer lead time processes than other RES-E technologies: the average planning time can be as long as seven years, and for half of the Member States it takes more than 3 years. As one can see, there is a clear-cut opposition between Northern and Southern Europe with lead times reaching seven years in Portugal whereas in Ireland, Austria and Germany, investors experience lead times to the order of two years.

Extreme lead times experienced in SHP projects are the following:

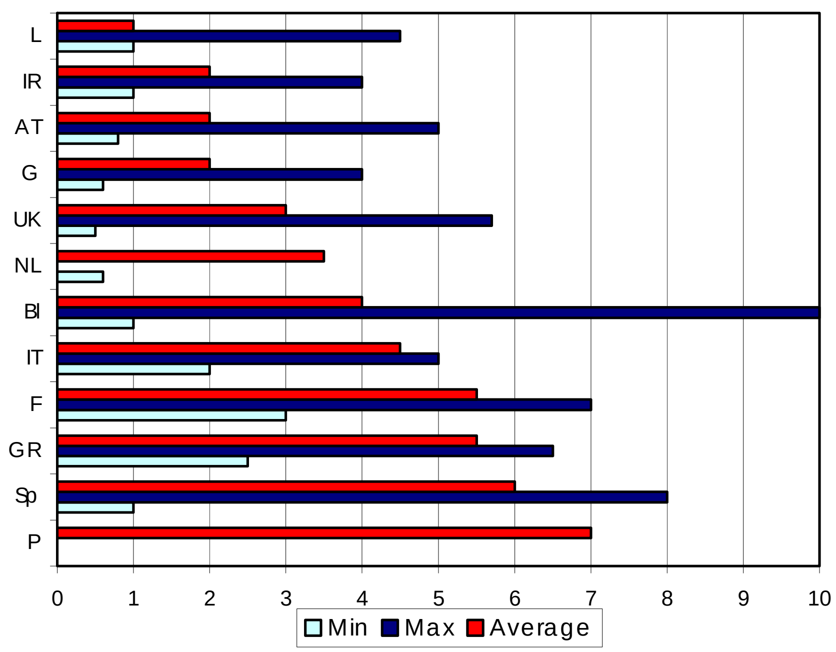

Figure 3.4 *Planning time extremes for SHP*

Different sources of delay

There are several sources of delays in the planning phase. One reason is linked to the nature of hydropower projects: hydrological measurements take a long time : at least one year to get the whole seasonal hydrologic activity, even more if the year is deemed not representative. Other sources of delays result from problems and conflicts. The BlueAge research (BlueAge, 2000), which has questioned experts on this subject, gives a thorough overview of what they are:

- Visual intrusion in a natural scenery. An SHP can be quite an imposing engineering work that can be striking in a natural landscape and judged to be degrading it. In several countries, ecological or neighbour associations oppose SHP projects because they impact too much on the setting. It is to be noted however that the opposition linked to that point is correlated with the type of plant: stronger for plants with reservoirs and weaker for a run off the river SHP, especially if only part of the flow is required.

- Fishery: an SHP can destroy fishways and hence destroy some migrating species. Fishermen associations can in some countries oppose an SHP projects on this ground. Here is an example of what is reproached to SHP by a French fishing federation: "How can one (...) accept the modification and banalisation of local landscape, the lowering of the quality of water because of its warming, because of eutrophication, smells, sewage, rarification of species (salmons, crayfish, migrating fish), transformation of the river profile, lowering of tourist activities (swimming, fishing, canoeing...), risks of accidents, noise."[17] According to the BlueAge research, these associations lead to the most serious problems regarding delays in SHP projects.

- Competing activities: water is subjected to different uses, which, even in countries where water is relatively abundant, lead to conflicts between different users. They are be of very diverse nature: fishing, protecting nature and landscape have already been alluded to, but there are also tourist needs, agricultural needs, water supply, transportation.

- Local authorities and administrative procedures: the number of required permits is huge, the administrations for these permits are not the same, all of which delays the licensing process so much that it can deter the submission of projects. Another problem is that, as well as for wind projects, local planning often does not include industrial water use in areas that are rural (which is often the case for SHP projects). The plan has to be re-qualified, which can mean more time spent waiting for the license. In the Netherlands for example it can take up to two years. Local authorities are sometimes also not respecting the time limit they have to answer an application, or simply not answering, which can be considered as a refusal (France)

- Connection to the grid: problems are the same as for wind power.

The table below surveys this for different Member States.

Table 3.2 *Different sources of delay for SHP*

Country	*Visual impact*	*Conflicts regarding fisheries*	*Competing interests*	*Local authorities / administrative procedures*	*Other*
Austria	Yes	Yes		Too many additional administrative requirements	Hydrological measurement. Additional ecological expertise that is asked for.
Belgium				Authorities take their time on small sites. Process is quicker for bigger plants.	Opposition on noise in populated areas

[17] From Hydro-energie magazine, n°28, December 2002, p21.

Country	*Visual impact*	*Conflicts regarding fisheries*	*Competing interests*	*Local authorities / administrative procedures*	*Other*
UK		Yes, quite strong. A significant proportion of SRO hydro scheme developers experienced planning delays giving rise to concern about their ability to commission within the 5 year building period.			
Finland	Yes	Yes			
France		Yes with France Nature Environnement, the Federation de Dordogne pour la pêche et la protection du milieu aquatique		No respect of time limits. No answer sometimes. Too much information is required without explanation. Schedule of authorisations is not coherent	Grid connection: longer than a few years ago. Can take up to 9 months, whereas it used to take 3 or 4 months
Germany				Unreasonable requests of authorities	
Greece	Very few conflicts have been cancelled because of environmental reasons.				
Ireland					Opposition on noise in populated areas
Italy				About 58 different permits from different authorities depending on the local site	
Luxembourg				Easier procedure as there are reactivation of ancient rights	
Netherlands	It seems there are no bottlenecks regarding SHP in this country. The only hindrance is linked to the potential.				
Portugal			Yes	Too many different permits	
Spain	Yes	Yes		Too many different permits. Very different procedures according to the CCAA.	

Country	Visual impact	Conflicts regarding fisheries	Competing interests	Local authorities / administrative procedures	Other
Sweden	Yes	Yes			

Construction time
Regarding SHP projects construction delays are surveyed in the following figure:

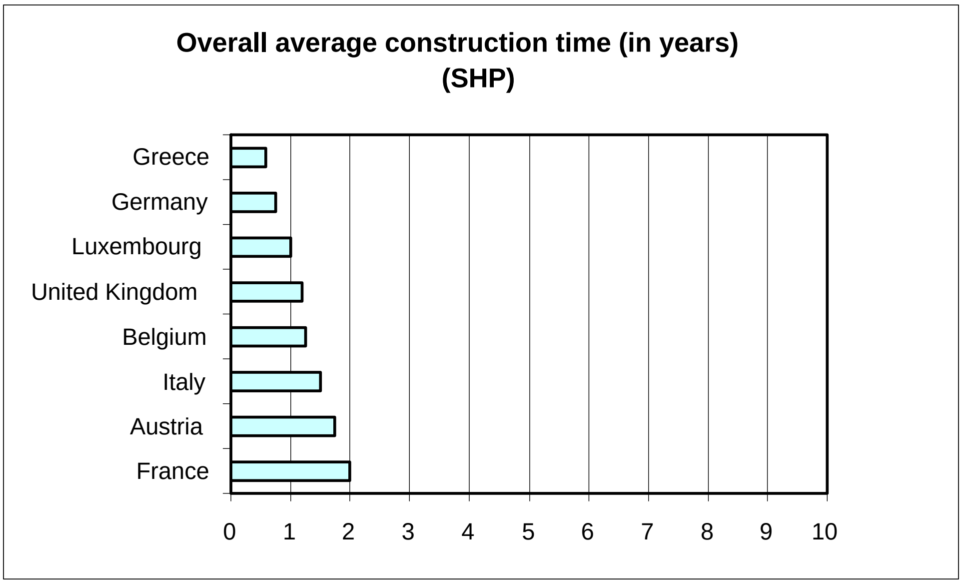

Figure 3.5 *Overall average construction time for SHP*

Construction delays are longer than all other RES-E technologies. They range from half a year to 2 years in France. Some delays can come from technical difficulties, but in general, SHP is a mature technology and construction is mastered and delays are easy to foresee.

3.4 Lead times for PV

The different steps in the planning phase for PV
The planning phase when considering PV is quite less complicated than for other technologies, mainly because PV has a much lesser impact on the environment in a large sense. Hence there is not EIA for PV or at least a simplified procedure, which makes less steps to follow. In some countries, like in Austria, if PV installations do not exceed a certain size they don’t even need permits.

There are two types of projects:
- The PV panels are part of a new construction.
- The PV panels are an addition on top of an already existing construction.

In the first case, the necessary permit is a building permit for the whole construction and not only for the PV installation. In the second case, the required permit is a declaration of modification / works. Both permits have to be requested from the municipal authorities. There can sometimes be specifications in the local plan of development, which investors have to check.

Another formality, in the countries where PV is supported by a public scheme, is to get the insurance of a financial support before starting the works. This is more usually granted by regional authorities.

The length of the planning phase for PV projects
In case of a new construction, lead times in the obtaining a building permit can come from multiple sources that have nothing to do with the fact that there are PV panels on the building roof. It is not possible to identify specific lead time for PV. Moreover, delays to receive panels are not long enough (around 6 months in France) so that they could heavily interfere with the construction of the building. Hence the delay is roughly the time needed to obtain a normal building permit.

In the second case, however, a permit is required to modify the already existing construction, and here lead times can be identified.

For existing houses the delay for obtaining the permit is only a couple of months.

Problems that can cause delay
In the Netherlands, there are some delays because works permit is given by a commission that judges the aesthetical aspect of the project in comparison to neighbouring houses. PV projects on existing houses are often refused whereas in new constructions they don't lead to refusal.

Problems that can delay the realisation of a project are linked with the financial aspects of the project rather than with authorisation to build. Waiting for the investment subsidy to be granted is one thing. In Belgium for example, it can take up to one year to be granted a subsidy. Waiting for a contract with the electricity company that will buy the production is another. France is a good example of difficulties in this regard. Because there are no specific contracts created yet so investors have to wait for their production to be bought that EDF establishes a standard contract. In one particular case (private citizen) the whole construction took a year and then a year and a half later, there is still no contract and electricity is not sold.

Construction time
Construction time is the average construction time for new buildings and takes only a few days for existing buildings.

3.5 Lead times for biomass projects

The different steps in the planning phase for biomass
Biomass has to be distinguished between organic biomass and waste. The conversion technology can be either combustion/incineration or digestion (methanisation).

As for other renewable energy projects, a biomass project implies to evaluate the resource potential. It takes a specific form in that it amounts to assessing and securing the supply chain. There can be some regulations regarding the means of transportation used by the resource and the distance it has to travel. There are also regulations concerning emissions generated to air, land or water. Because of emissions, biomass projects are often subjected to EIA to get the authorisation to produce, except for projects of biogas on farms, which are generally small installations and are badly needed to dispose of all the animal manure produced by the EC. On top of that, a construction permit will be required in all countries.

Due to the European Environmental Directive on Waste Incineration (2000/76/CE), Member States have to treat waste separately from energy crops and crops residues. The handling of waste is supervised by municipalities which determine how to get rid of it: generally they advocate recycling in the first place, many municipalities are more and more interested by methanisation for the treatment of waste. This directive imposes that the public is informed of the project of incineration plant. For investors, it means that projects dealing with municipal waste will be the subject of a call for tender from the municipalities.

The table below surveys the specific requirements from individual Member States.

Table 3.3 *Specific emissions requirements from individual Member States for biomass projects*

Country	*Environmental impact assessment*	*Emission permit*	*Specification for authorisation*	*Specific requirements for waste*
Austria		Act on the prevention of air pollution through boilers regulates the installation and equipment of boiler installations.	Permission required from the Provincial Government if emissions exceed 2 m^3 of gas an hour. In the case of boilers, the authorisation can include a public enquiry. The permission is granted by district administrative authorities.	
Belgium	No EIA below 3 MW. Over 5 MW follow TA-Luft regulations on emissions		Yes	
Denmark	Environmental approval is needed over 1 MW fuel input and also for biogas plants with a daily capacity of more than 50 t of manure or vegetable waste.		Getting approval from the Danish energy authorities	All power for waste handling are given to municipalities who can impose on private industry
UK	If considered relevant for biomass	Integrated Pollution Control and Air Pollution Control by local Authorities, administered by the Environment Agency : for waste and biomass combustion project		A Duty of Care is imposed to any organisation which handles waste EIA mandatory for waste disposal installations
Finland		Guidelines on particulate emissions for biomass		Specific guidelines on emissions Waste Act and Waste Decree
France	Yes over 4.5 MW		Declaration between 2 and 20 MW Authorisation over 20 MW, which lead to public enquiry	ICPE study is heavier than EIA. Takes 6 months. Implies a public enquiry.

Country	*Environmental impact assessment*	*Emission permit*	*Specification for authorisation*	*Specific requirements for waste*
Greece	Biomass projects between 2 and 50 MW require an EIA.			Municipalities decide on waste treatments
Italy		Permits for emission on water, land and air		
Luxemburg				Additional authorisations are necessary
Netherlands	Yes, takes 6 months Some barriers to the production of energy crops: use of ground water is regulated; use of land, location of the area (not further than 30km from the convergence)			Separate handling of waste in the EMA permit: for the collection, treatment, and storage. Permit for handling biomass is limited to 10 years. Incineration of waste leads to specific rules. (cf. Circular 'Optimisation of waste disposal')
Spain	Yes for combustion			
Sweden		Activities with emissions on water, land and air are considered hazardous for the environment and are treated specifically by the County Government board if they range from 10 MW to 200 MW and by local authorities if they range from 500 kW to 10 MW.		Chapter 4 of the environment code. A will on the part of many municipalities to promote biogas installations.

Length of planning and construction phase

Delays experienced by investors for biomass (not waste) co-combustion projects are the following:

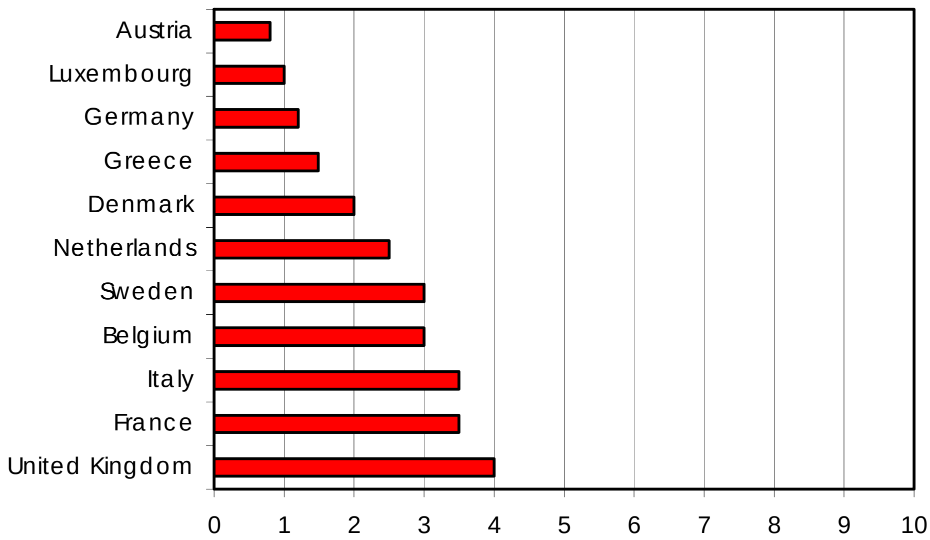

Figure 3.6 *Overall planning time for biomass (years)*

Planning times for biogas seem a little shorter. What takes time is the building of the supply chain.

Problems that can cause delays:
In general there is a better local acceptance for methanisation than for combustion (which seems more pollutant to people). For example, in Germany for the moment biogas appears as a new ecological energy source and subsequently has a very good public perception. As many biogas plants are under construction, it can be expected that problems caused by odour, waste, transporting traffic will introduce some aspect to this generally positive impression.

There is also a good administrative context. In Luxembourg, for example government is very much in favour of biogas. Administrations, local authorities and developers work hand in hand. The failure risk is almost non-existent.

Construction and commissioning
Construction length is quite coherent between countries: 1-2 years.
Commissioning is a longer process than for other renewable sources because of emission measurements that have to be done.

3.6 Permission from local authorities or councils

Section 3.1 lists the different steps an investor has to take in the planning phase of a project in the renewable energy sector. A crucial point is the obtainment of the necessary permits from local authorities. Difficulties of obtaining permits pose a risk. Fluctuations in the lead-time and in the transaction cost may reflect this risk. In some Member States the lead-time can be considerable. Even in standard procedure and time schedules the actual lead-time may fluctuate. In addition the cost connected to obtaining the permits (transaction cost) may fluctuate, e.g. additional pre-analyses and pilot studies have to be made.

Investors are not sure to get the authorisation even if they follow all the procedures. A proposal to measure this risk was to ask investors how many projects they would present to get one go ahead (The success rate). One can evaluate the number of projects that have to be presented to get one permit in the wind power sector as the following. The two graphs below indicate these numbers for different Member States.

Table 3.4 *The success rate in wind power*

1	2	2-3	4	5	10	[year]
Ir	Lux	It	DK	G	Sp	
				UK		
				Bel		
				Fr		

Table 3.5 *The success rate in SHP*

1	2-3	3	4	5	5-6	[year]
BL/Lux	AT	GR	G	It	FR	
				UK		

Regarding SHP, all countries have a rate of failure except those where there is more reactivation of ancient rights (Belgium and Luxemburg). The figures illustrate the difficulties of getting a permit. However, expected administrative delays and risk of not being authorised, often lead investors to increase the number of projects presented in order to get one permit, even if some of these projects are not fully economically feasible[18].

Hence, the failure rate number is not to be taken for granted (especially in the investor’s calculations of the required revenue for green value of electricity). In addition, it comes from a small number of interviews. And investors can have different ways of approaching this stage: on the contrary some try to present few requests but really carefully study them and validate them with local actors in order to lower the risk.

In fact, the more numerous the problems, the longer the lead times. And the problems creating lead times are also the sources of failure for the project: opposition from local associations, difficulty for the authority to issue a decision, competing uses, etc.

Regarding PV, the risk of not being granted a permit is linked with the architectural project if the construction is new. It has to be stated that integrating PV in a new building is probably an advantage regarding obtaining of a building permit. Indeed, most Member States have programs to promote passive and active use of solar energy and find it hard to induce investments in this expensive technology. The failure rate is more to be linked to actually getting the financial support. If the construction already exists, failure can be encountered in the Netherlands because permission is not granted.

3.7 How to reduce lead time?

There are several directions to take for reducing lead times. They are valid whatever technology is concerned. Some of them depend upon investors’ work, others from administrative regulations.

When examining causes of delay, we have highlighted the recurrence of conflicts with local actors. Of course, nuisances can be reduced by R&D. But technical and rational aspects are not all. Conflicts are often generated because of a lack of understanding of the project and its impacts. It is up to the investors themselves, and many already do, to seek consensus with local actors.

[18] In Spain for wind power, and in several Member States for SHP (especially France). It is a sort of negative feedback process: expected delays and non-approval leads to submission of many projects, some of which are not feasible, which increases the non-approval rate, which, in turn creates the feeling that approval is difficult. This may explain the low success rate in those countries.

More weight is given to the public in the decision process, mainly upon the influence of European legislation.

Local authorities, which have the power to grant construction permits, are also very important to consider at an early stage of the planning phase. Investors should consult local actors by doing more fieldwork: meetings of information, early consultation with the planners. The public has to feel his demands are taken into account. Market research should be done in order to know how to explain a project, what are the informational and emotional needs of the public who will be presented the project. Investors have to tackle the issue of what the impacts of a project will be in order to prevent the forming of collective anxiety around their project. In short, more transaction costs should be devoted to the preparation of a project in order to reduce costs in the end.

The other main source of delay is administrative procedures. Investors can prevent part of the delay by legislative monitoring and political lobbying. But the main action here is for competent authorities to simplify and clarify procedures, there are general principles that have been stated during workshops and interviews with experts and that have been also developed in studies:

- Identification of favourable sites both from the resource potential (e.g. Luxemburg's wind power Atlas) and from the local planning perspectives.
- Revise local planning when a clear strategy for the development of renewable energy sources is missing. Elaborate a guide to local authorities as to how plan RES.
- Idea of a one open window: one interlocutor for all permits and document deliveries.
- Explicit guidelines on what is needed and established standardised indicators: what documents, presentation, themes, specifications. This is above all valid for EIA.
- Pre-examination of a project in order to scan from the start projects that have no chance of being granted authorisations.
- Imposing a mandatory time frame to authorities.
- Create lighter procedures for small projects.

4. TRANSACTION COSTS RELATED TO INVESTMENT IN RENEWABLE ELECTRICITY PROJECTS

As discussed in the previous chapters, investors in RES-E encounter various administrative steps to be taken previous to the actual construction of a plant. Explicitly or implicitly most of these steps lead to costs, which can be referred to as *transaction costs*.

In general, transaction costs are the costs that arise from initiating and completing transactions, such as finding partners, negotiating, consulting with lawyers and other experts, monitoring agreements, etc., or opportunity costs, like lost time and resources. The most obvious impact of transaction costs is that they raise the costs for the participants of the transaction, i.e. the investors, and thereby lower the expected profits or even discourage some transactions from occurring. In this case they prevent investments from being undertaken. The aim of this section on transaction costs is to give an overview of potential cost drivers and to create awareness of their importance. Investors may want to use the given framework to structure several sources of transaction costs and include them in their economic analysis of an investment project.

The complete process of an investment in a renewable electricity generating plant can be considered as one sequence of transactions. Therefore, transaction costs are those costs that go beyond the pure investment costs and arise from various sources. Transaction costs arise in different phases of an investment project (see also Section 3.1). These phases are illustrated in Figure 4.1 below

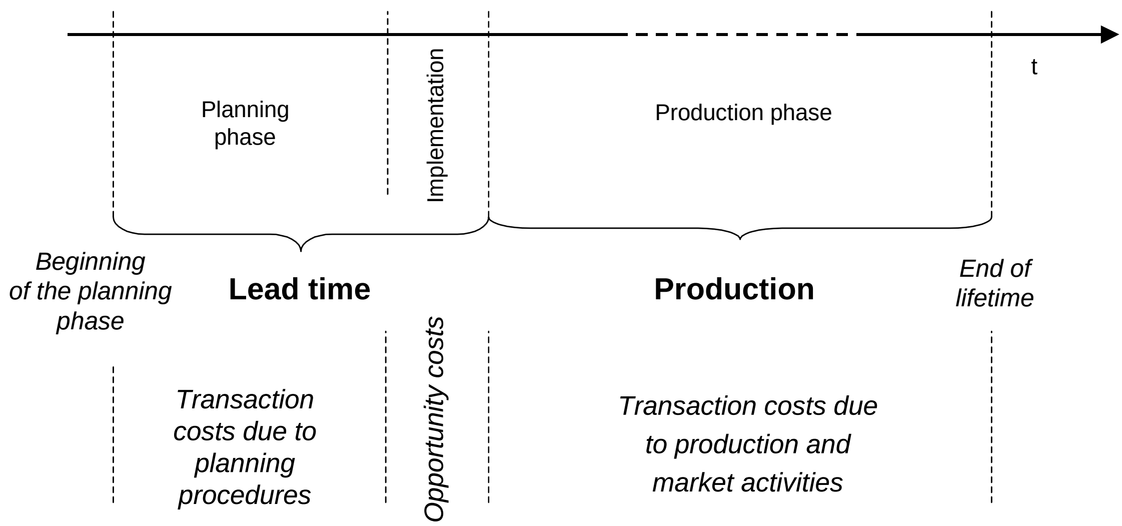

Figure 4.1 *Different phases of an investment project and associated transaction costs*

The *planning phase* can be subdivided into three further phases:

- *Search / pre-feasibility phase*: Finding interested partners to the transaction as well as identifying one's own position and optimal strategy. Examples may be the search for a suitable site, the choice of the desired technology, the rough determination of the available budget and - as the last action in this sub-phase - the accomplishment of one or more pre-feasibility studies.
- *Negotiation / development phase*: Coming to an agreement. For example, negotiating the terms of a contract takes time, and can include visits to the project site, and hiring lawyers to draft contracts. Other examples may be the evaluation of different financing schemes for the project or negotiations regarding loans as well as economic and technical feasibility

studies. This sub-phase usually ends with concrete investment projects, i.e. the aim to invest in specific technologies at specific sites.
- *Approval / administrative procedures*: The planned investment must be approved by a government agency. Modifications could be imposed on the deal.

Transaction costs in the *implementation phase* are opportunity costs and are determined by the *Construction and commissioning time* i.e. the time from obtaining the building permit to selling the electricity.

Also the *production phase* can be divided into sub-phases. These are:
- *Monitoring*: Efforts the participants must make to observe the transaction as it occurs, and to verify adherence to the terms of the transaction.
- *Enforcement*: Time and expenses to insist on compliance once discrepancies are discovered.
- *Adjustment*: Time and costs of changing strategies, due to a change in regulations or new scientific discoveries.

Transaction costs can either be real expenditures or work load. Note that the first two phases are strongly connected to the lead-time of an investment project. More precisely, those phases of the lead-time in which an investor is 'active'[19] can be used to transform the time into transaction costs. Any phase in which an investor is 'passive'[20] can be considered as opportunity costs. Any type of transaction costs arising from these two phases raises the total costs of the investment project.

Trade in Green Certificate markets also is a source of transaction costs. Usually this category of transaction costs applies to all participants in the market, i.e. producers and customers of green certificates (TGC supply and demand). Although trade in green certificates can be seen as a transaction itself the resulting costs may lower the profits from the RES-E investment projects and, thus, can be seen as a part of the projects' transaction costs in the production phase.

As soon as markets for certificates emerge, brokerage firms are expected to enter the market, who will provide information about firm's production options and potential trading partners. Although brokers will have to get paid, their activities will reduce transaction costs below what they would be otherwise. So the costs which are likely to be the most significant component are brokerage fees.[21] To get a first idea about the development of those fees a survey of similar markets, e.g. emissions trading markets[22], seems to be an appropriate starting point.

According to several studies[23] brokerage fees constitute approximately 5% of the total traded value. However, these schemes are national schemes and it can't be taken for granted that transaction cost ranges are the same for international trading. In accordance with these studies transaction costs can constitute 10% of the traded value (at the beginning of the trading program) down to 2% of the traded value (in mature and highly liquid markets).

4.1 Transaction cost figures - a qualitative survey

According to our qualitative survey described in Chapter 1.1, for which detailed results are given in Annex A, quantification of transaction costs lead to two major conclusions.

[19] I.e. where an investor explicitly employs workforce for negotiating, searching, monitoring etc.
[20] I.e. an investor is waiting for a proposal being approved etc.
[21] Note that it depends on the market structure of the trading scheme whether supply or demand is charged with brokerage fees.
[22] With regard to international emissions trading search and negotiation costs are likely to be significant compared to domestic programs. However, with regard to international trading it is problematic to obtain applicable estimates, as there has been little experience to date in the operation of internationally-based emission trading schemes. Transaction costs that occur in domestic trading schemes, like the U.S. lead or SO_2 trading markets, can serve as first estimates.
[23] See e.g. Klaassen and Nentjes (1997), Montero (1997), MMA (1999).

- Transaction costs are extremely case specific.
- As a consequence, a broad reliable database can't be given.

Many actors at the RES-E market see administrative burden and approval procedures as a large source of transaction costs. Not only the delay of time from initiating necessary administrative steps to the feed-back from authorities (opportunity costs) but also the workload in the planning phase seem to be major cost drivers. Actors have difficulties in providing explicit and general transaction cost measures. They indicate a very case specific nature of transaction costs.

The responses to the qualitative survey show that transaction costs are subject to fluctuations. The given values scatter to a large extent. Figure 4.2 below illustrates the range of indicated cost measures.[24] The assumption that administrative steps and approval procedures have a large impact on the magnitude of costs seems to be proven by the fact that actors indicate a rather large range of transaction costs in the planning phase of the project compared to the production phase. As a consequence, cost drivers in the first phases of a project are much harder to predict than in the later phases.

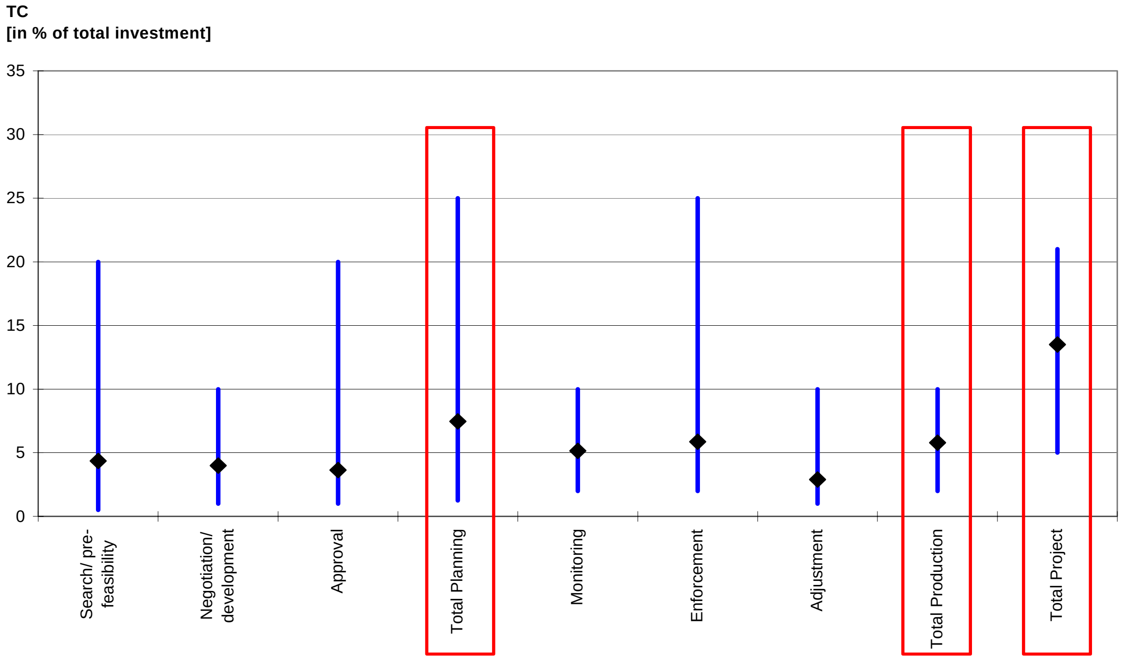

Figure 4.2 *Adjusted bandwidth of indicated costs (without extreme values)*

Another relevant issue in the context of transaction costs seem to be failed projects. In our survey we asked about the number of planning phases an investor has to start in order to implement one successful project. The values range from 1 (successful project per planning phase) up to 10 (planning phases for one successful project). The average value has a magnitude of roughly 3 planning procedures per successful project. In combination with the given transaction costs in the planning phase, failed projects may significantly raise costs for the successful projects. But if and how failed projects affect the economic viability of one successful investment project depends on the inclusion of these overhead costs in the economic analysis performed by the investor and, hence, on controlling and accounting systems.

[24] Minimum and maximum values were dropped in this analysis in order to avoid the influence of very extreme special cases.

4.2 How to reduce transaction costs?

Transaction costs can sum up to a considerable amount of the overall investment (up to 16%). With this upper bound it seems reasonable to think about ways of reducing the costs that go beyond the pure investment costs in order to decrease the threshold values for successful RES-E investments.

Many components of the transaction costs are due to specific demands of the investors and therefore not considered under this section. On the other hand, the administrative burden might be too high and the approval procedure much too lengthy. Reasons are especially the inclusion of local interest groups in the planning process, the masses of materials that have to be delivered in order to receive final approval as well as delays caused by slow reacting authorities. In this regard many of the measures leading to a reduction of transaction costs can't directly be influenced by investors.

Concerning the streamlining of the procedure, the following measures are conceivable:
- bundling of administrative steps,
- establishment of organisations supporting the investors on their way through the planning process,
- land use planning,
- harmonisation on the EU level concerning treatment of small scale investments.

Investors have to cope with many regulations and thus to deal with different local, regional or national authorities. Countries interested in the promotion of RES-E could implement one focal point for investments channelling the approval procedure. The investor would have to deal only with one contact instead of several. An alternative could be the implementation of support organisations leading the investors through the different administrative steps. Furthermore, countries could support RES-E investments if they include the demands for sites for RES-E investments in their land use planning. This would also reduce the risks of delay and the efforts spent for a successful approval caused by the concerns of local interest groups. These concerns would be tackled beforehand by the planning authority. Last but not least, several Member States have special treatments of small-scale investments with reduced administrative requirements. These requirements as well as the definition of small-scale investments differ across the EU. A harmonisation would lead to more transparent regulations and therefore encourage investments across borders.

As mentioned above, part of the transaction costs are caused by specific investor demands. It is hard to come up with proper generalised recommendations how investors could reduce transaction costs on their side as it can be assumed that they better know their internal organisation and communication processes than we do. One option for firms to act towards the reduction of transaction costs is to lobby towards a streamlined approval procedure. Besides this, the implementation of a focal point (as mentioned above) could also be an initiative of a group of investors or an association. Knowledge about market research, local legislation and best practices can be bundled and offered investors as services.

5. RISK DESCRIBED BY FLUCTUATIONS IN REVENUE

Another challenge for an investor lies in identifying risk described by fluctuations in revenue when the production is running. Fluctuations in revenue make an investment risky since the realised revenue from the investment can turn out smaller than the expected revenue thereby lowering the profitability of the investment. Therefore, an investor[25] will require a risk premium in order to invest in a risky investment project compared to investing in a less risky project. In other words, the risk premium represents compensation for undertaking the risk of the realised revenue becoming smaller than expected.

5.1 Creating a framework for analysing risk factors in different policy designs

The causes to the fluctuations in revenue are numerous. For a potential investor the large amount of causes and effects of risk connected to an investment can seem boundless. Therefore, the challenge lies in simplification and in creating a suitable framework for analysis of policy designs and modelling of investor's risk premiums.

The framework should make it easy for investors to identify major risk sources, classify their importance and create satisfactory estimates of the parameters needed to evaluate the investment opportunity.

In the following we have listed alternative ways of dividing basic risk factors into different categories. As a success criteria for this type of division we look at four basic functions that such a framework should serve:

- Enable decision-makers to quickly identify separate risk factors, their importance and their interdependence.
- Enable a division or generalisation of different types of risk factors across categories such as type of technology or geographical region etc.
- Analyse the effect that policy instruments will have on investor uncertainty and thus the required risk premium.
- Facilitate the modelling of investment risk in a model such as ADMIRE-REBUS.

When setting up a framework it is important that these basic functions govern the structure that is chosen, i.e. the structure of the framework should be suitable for the subsequent analyses. There are two intuitive ways of characterising risks, depending of the motivation for doing so. If the risk considerations are done in order to collect data or estimating where the risk originates from one should characterise the risk according to the sources of risk. If the risk considerations are done in order to estimate the effect on revenue one should characterise the risk according to the component of revenue.

If the risk is characterised according to the sources of risk, one can distinguish between *political, technological* and *market based causes*[26] as illustrated in Figure 5.1. This approach makes it easy to extract information from data e.g. technological data, market data or political trends. In this framework market risks and technology risks are largely related to inherent risks in the existing system and it will often be possible to model the individual components using statistical distributions.

[25] If he is risk adverse.

[26] The separation of these risks has been undertaken for analysis purposes, but (as in any system) the three sets of risks are interrelated and multiple inter-linkages and feedback processes among them exist.

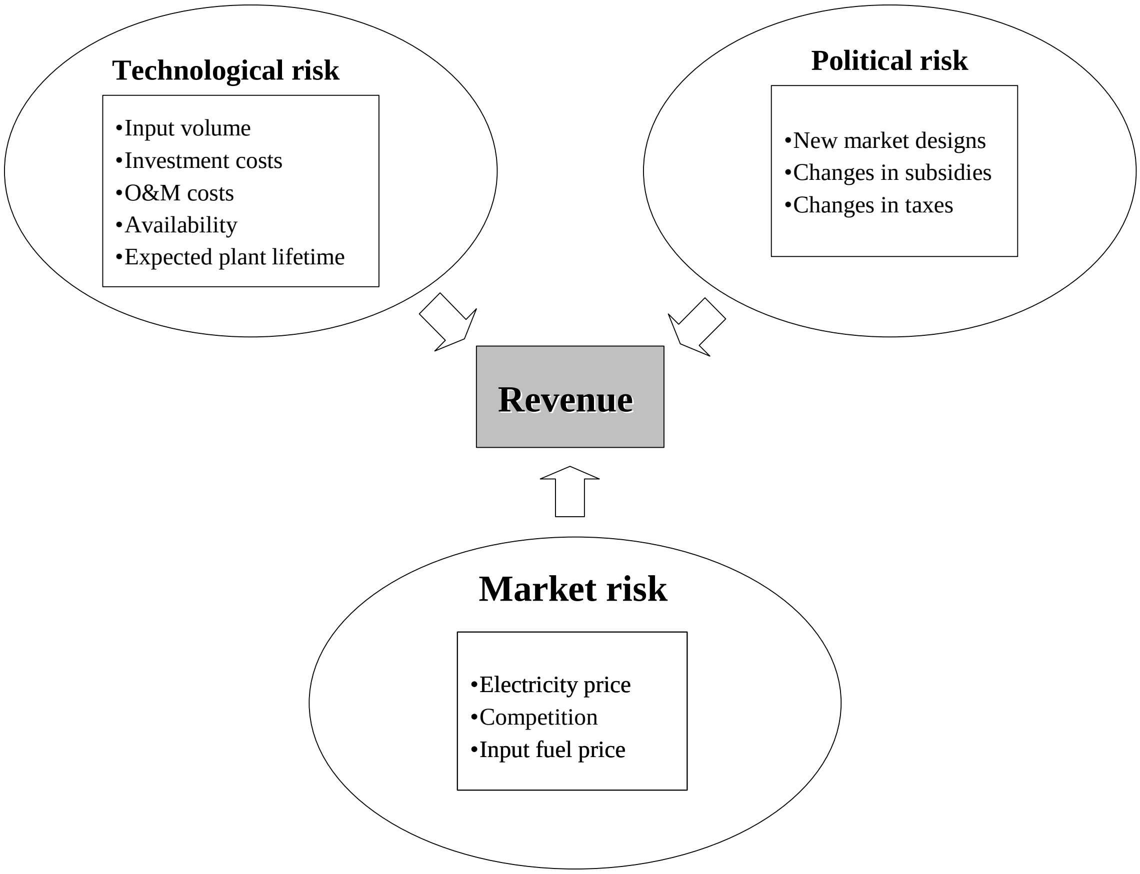

Figure 5.1 *Risk factors divided into Technology risk, Political risk and Market risk*

Market risk holds all risks related to the currently chosen market structure and technology risk covers all technical risks related to the costs and availability of the plant. Political risk is related to possible changes in the system based on political decisions e.g. the switch from a feed-in tariff to a TGC system. This type of risk is generally more suited for a qualitative form of analysis where each political decision is analysed as a scenario. Political risk is thus seen as a binary variable: either a new market design (e.g. support scheme) is chosen or it is not.

With respect to analyses of how the different risk factors affect an investment decision it is a useful exercise to look at the direct effect that each risk factor will have on the revenue and the required risk premium. Revenue is a product of price and quantity and profit is obtained by subtracting costs. To analyse financial risk a division into the following three components shown in Figure 5.2 below, can therefore be useful.

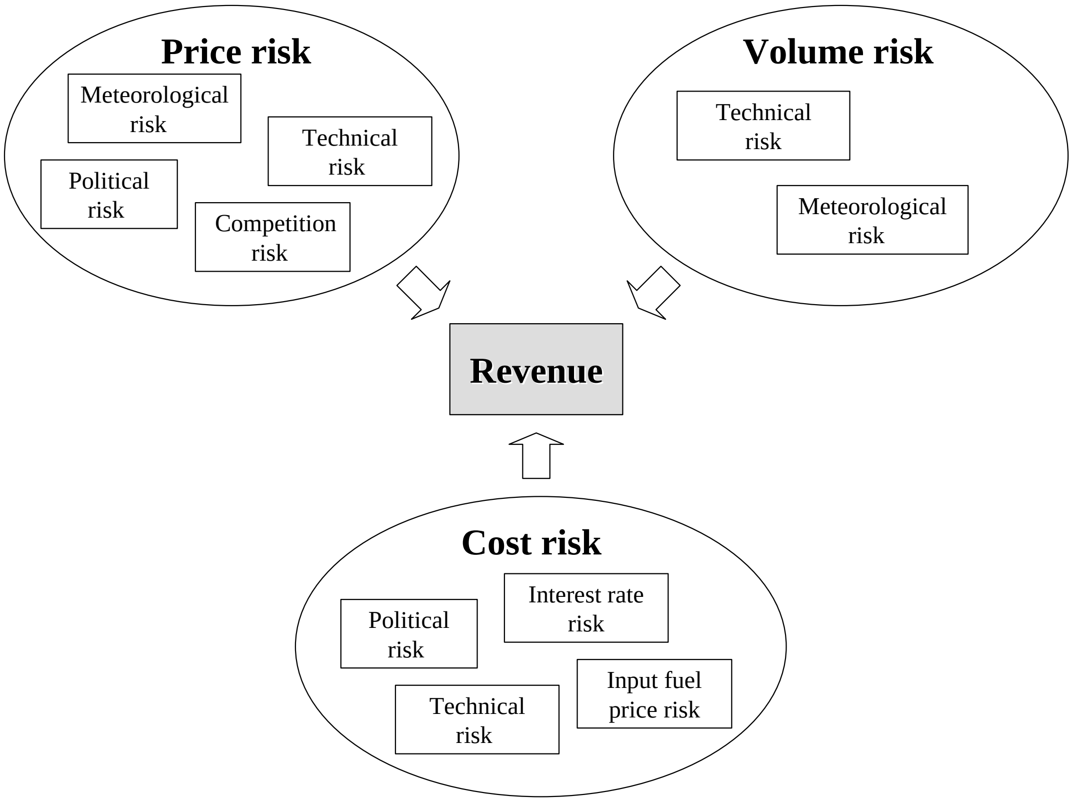

Figure 5.2 *Risk factors divided into three categories: Cost, Volume and Price*

This division has the advantage of focusing directly on the factors, which must be modelled in order to value an investment opportunity. Looking at the individual risk types we can see that a factor such as technical risk is included in all three categories. Production cost is affected by accidents, maintenance etc. Prices can be influenced by technical factors in numerous ways e.g. if a transmission line or large plant is down capacity can become scarce in a certain region and prices will tend to rise sharply. Finally the volume produced will clearly vary significantly when forced or planned outages occur.

For an investor, the choice of grouping is a matter of taste. For aspects of analyses of the effect on the revenue the latter framework of grouping (Figure 5.2) might be most suitable. However, the former grouping (Figure 5.1) seems more pedagogical and intuitive. In addition, with this framework it is easier to extract information from data e.g. technological data, market data or political trends. Therefore, for a potential investor, who is collecting data for risk described by fluctuations in revenue from a RES investment, we suggest to use the former grouping of risk factors (Figure 5.1, technological, market and political risk).

5.2 Interpretation of risk

In order to analyse the effects of the different risk factors for a given investment it is useful to focus on the factors that are most important for the investment and that are hard to predict, i.e. the factors that bring most risk to the investment.

Obviously, different technologies face the risk factors differently. Therefore, there is not a unique way to order the factors according to importance for the investment and how predictable they are. It depends on the technology, the location, the country, the policies, etc.

Again the challenge lies in simplification and in creating a suitable framework for analysis of which factors each investor has to pay attention to.

A simple and useful framework is to make a comparative presentation with focus on the qualitative relations between the factors. We look at two sides of the factors - importance and predictability - both rated at a scale between 1 and 5. The ranking for importance is 1=very important, …, 5=not important, and for predictability is 1=very uncertain, …, 5=certain.

A graphic presentation of these factors can be seen in Figure 5.3, which indicate the relations between importance and predictability.

In order to compare the different factors we split the figure in four parts. Each part defines a degree of risk connected to the investment. The most important and unpredictable factors define the most risky parameters as these that are within the lower left corner at the figure. These are the factors that are important for the investment and that have fluctuations, i.e. that are hard to predict.

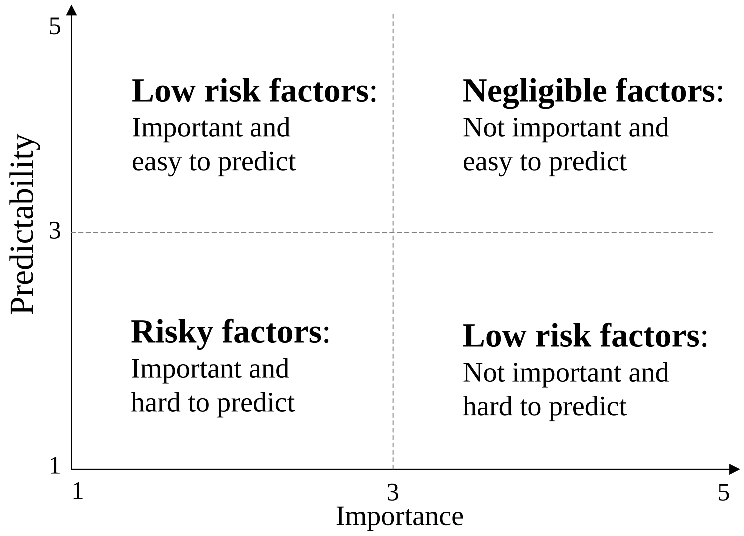

Figure 5.3 *Characterising risk factors*

If a factor is important for the investment and at the same time easy to predict (upper left square in Figure 5.3) we define it as a low risk factor, i.e. only a little amount of risk is connected to the factor.

If a factor is not important for the investment and it is easy to predict (upper right square in Figure 5.3) we define it as a negligible factor. In this case it does not create any significant risk for the investment. Therefore, these factors can in most cases be neglected in a risk analysis of an investment project.

If a factor is hard to predict but has a low importance for the investment (lower right square in Figure 5.3) we define it as a low risk factor. Even if the factor faces heavy fluctuations these fluctuations will only have a small impact on the revenue from the investment. Therefore, it will only contribute with a low risk impact on the investment.

5.2.1 Questionnaire analysis - Risk

As mentioned in Section 1.1 a small questionnaire analysis was done within the ADMIRE REBUS project, in order to get an appetiser of how the interpretation of risk is in different countries with respect to investments in different renewable energy technologies.

In line with the framework discussed above the analysis determined which factors are regarded as the ones that make the investment risky. The risk factors were grouped in three categories; technical, market, and political factors (see Section 5.1). The interpretation of the different risk factors and groups may differ from investment in different technology or countries. Therefore, the analyses of the responses first looked at the factors connected to different technologies and countries. Then general risk interpretations were made.

The sparse representation of some of the technologies and countries implied that it was hard to draw conclusions for these technologies and countries based on the questionnaire responses. Therefore, the analysis makes some general conclusions and uses a few technologies and countries instead of a detailed analysis. In other words, the analysis only gave an appetiser of how the interpretation of risk is in different countries with respect to investments in different renewable energy technologies.

The analysis of the responses first looks at all technologies in order to have a reference case for comparison between the technologies with respect to the interpretation of risk. It was noted that wind power was the dominating technology in the responses (see Section 1.1). This is however also expected to be the case in deployment of different technologies.

The figure below (Figure 5.4) illustrates the responses with respect to importance and predictability for all technologies. The numbers are average of all the responses.

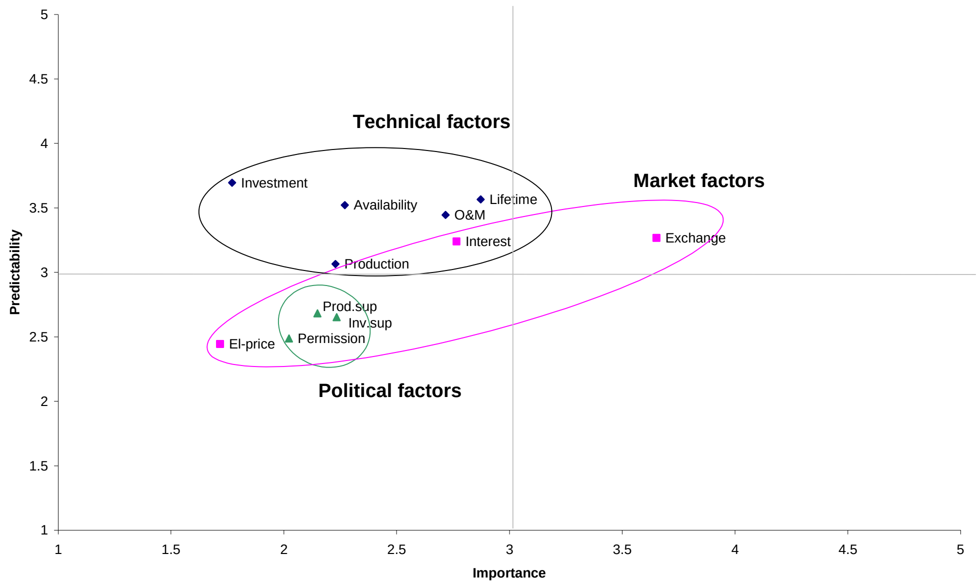

Figure 5.4 *All technologies and risk factors*
Note: The ranking for importance is 1=very important, …, 5=not important, and for predictability is 1=very uncertain, …, 5=certain.

It is seen that all the political factors are looked at as risky and that the technological factors are looked at as low risk factors. A general statement for the group of market factors can not be found. The electricity price is looked at as risky, the interest rate as a low risk and the exchange rate as negligibly risky.

From the responses of the questionnaires most investors said that the investment costs are very important, whereas O&M costs and lifetime are not. This is illustrated in the horizontal direction in Figure 5.4. Overall investment cost was rated as the most important technological parameter.

From the political factors, permission from local authorities and councils was stated as the most important factor. This is also in line with many of the responses that said that political factors are almost impossible to include within the NPV-calculations due to the low predictability (see discussion below).

On one hand, the importance of the different risk groups (technological, market and political factors) are more or less the same. On the other hand, the predictability differs!

Wind power
We now look at a single technology -- wind power. First in general for all countries and later for wind power in three different countries; France, UK, and Denmark.

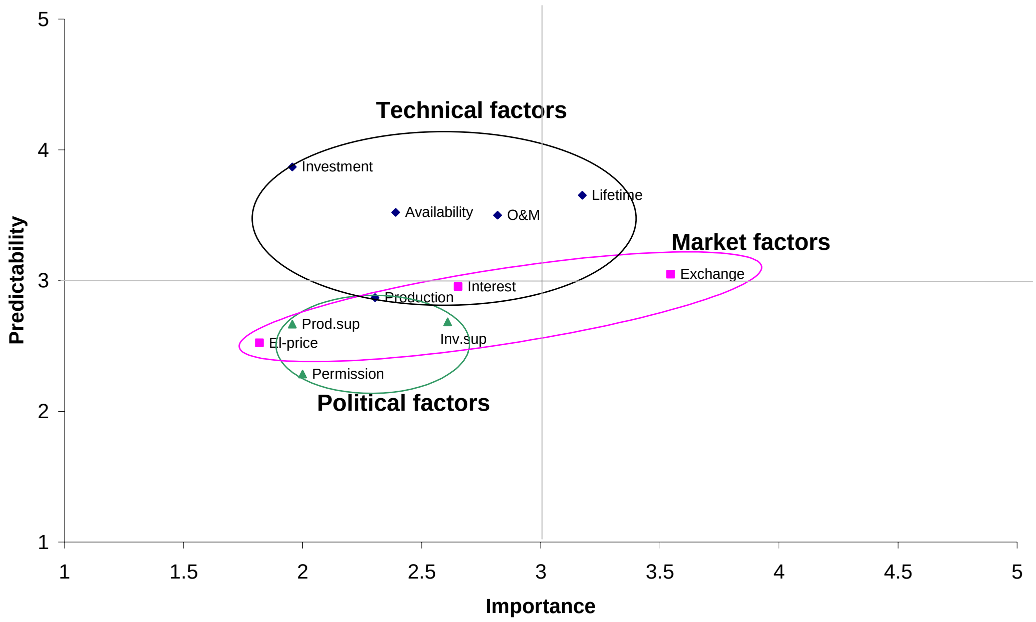

Figure 5.5 *Wind power for all countries*

When we look at wind power in general (Figure 5.5) we see that it differ a little from the general view (Figure 5.4). Annual production and interest rates become risky factors. However, the disparity is minimal. The reason for this is that wind power represents most of the responses.

In order to see if the perception of risk differs between countries we now look at wind power investment in Denmark, UK and France and compare these responses.

The first figure (Figure 5.6) represents wind power in Denmark. Looking at the political factors, only permission from local authorities/councils is considered risky. This is a change from the general view (Figure 5.4) where all political factors were looked at as risky.

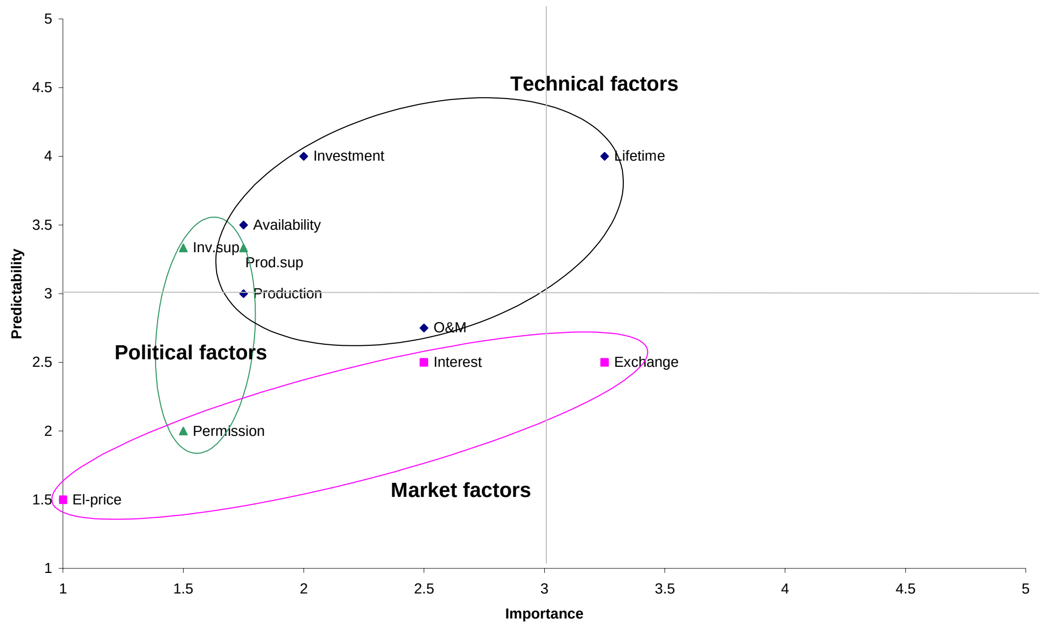

Figure 5.6 *Wind power in Denmark*

In Denmark the market factors are looked at as more risky than the general view. Especially the electricity price is mentioned as a risky factor. We now look at the responses for wind power investment in the UK (Figure 5.7).

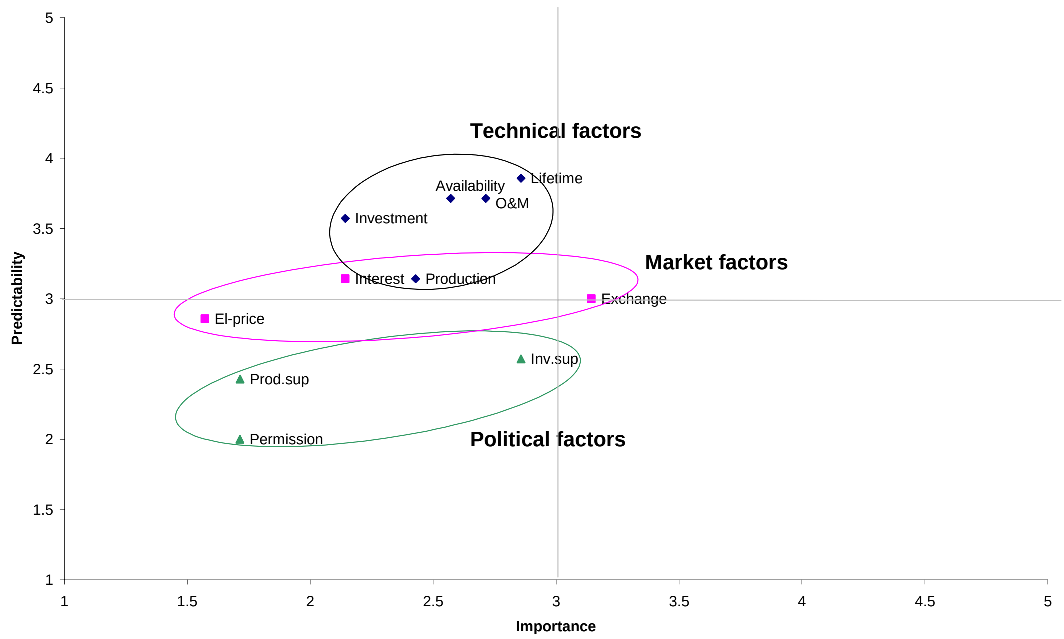

Figure 5.7 *Wind power in the UK*

In the UK all the political factors are looked at as risky like in the general case. Likewise, are all the technical factors looked at as low risk factors - as in the general view.

Finally, we turn to wind power investment in France (Figure 5.8).

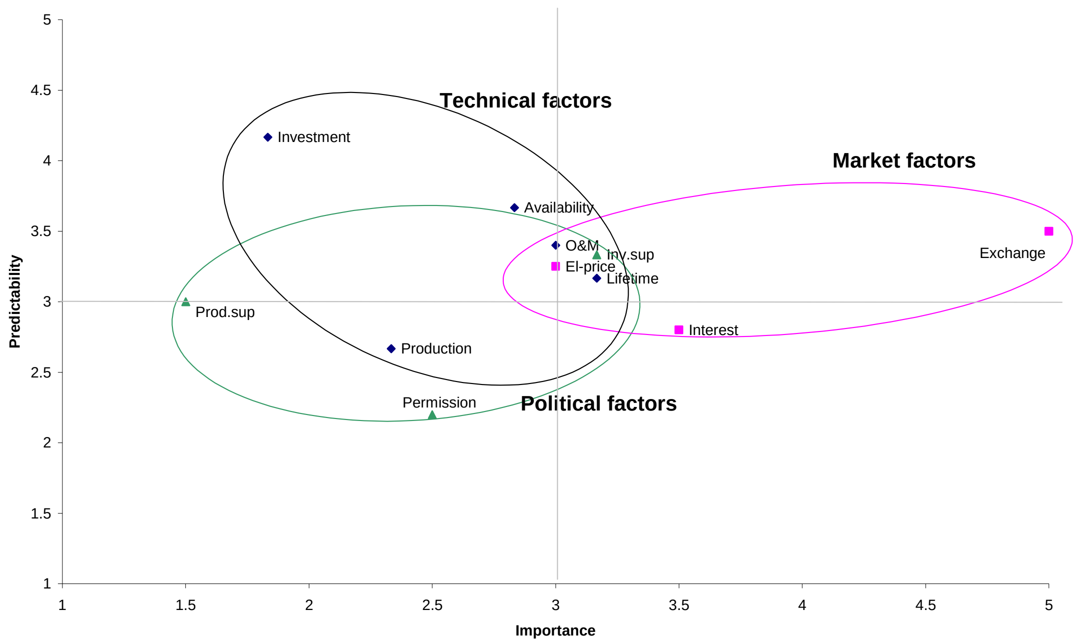

Figure 5.8 *Wind power in France*

If we compare the responses regarding wind power investment in Denmark, France and the UK we see that the risky parameters differ a lot. In other words, even though we look at a single technology the interpretation of risk differ between the countries. Only the factor for permission from local authorities/councils is looked at as risky in all three countries.

For France we observe that the market factors are looked at as negligible factors, which is the opposite of the responses from Denmark. This of course has to do with the present policy regimes and degree of market related support systems. In the discussion below of market risk we turn to this observation.

In general we conclude that the interpretations of the technological factors are more or less the same for wind power investment in the different countries. Whereas, political and market factors are interpreted differently in the different countries.

Photo-voltaic (PV)

In order to see if the perception of risk differs among the technologies, we now look at investments in PV and compare the results with wind power.

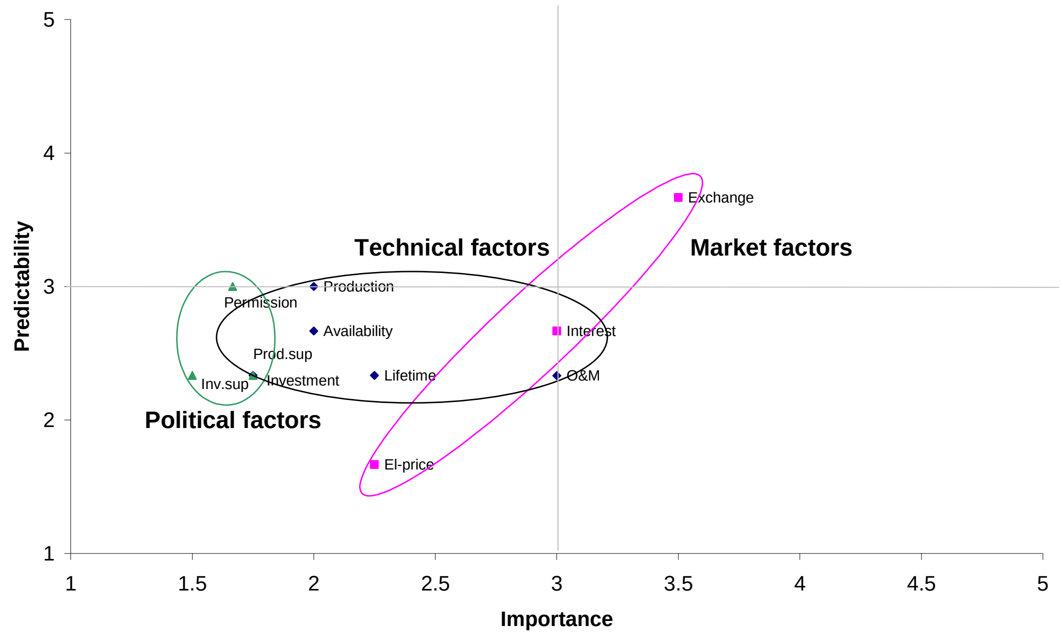

Figure 5.9 *PV for all countries*

For investment in PV we notice that all the technological factors becomes risky factors! Compared with wind power PV is still an immature technology, the technological factors are regarded less predictable than mature technologies (e.g. wind power).

PV is often supported by fixed tariffs rather than by market based systems. Therefore, the political factors are looked at as more important for the investors than the market based factors.

Biomass

We can make a similar comparison between biomass and wind power.

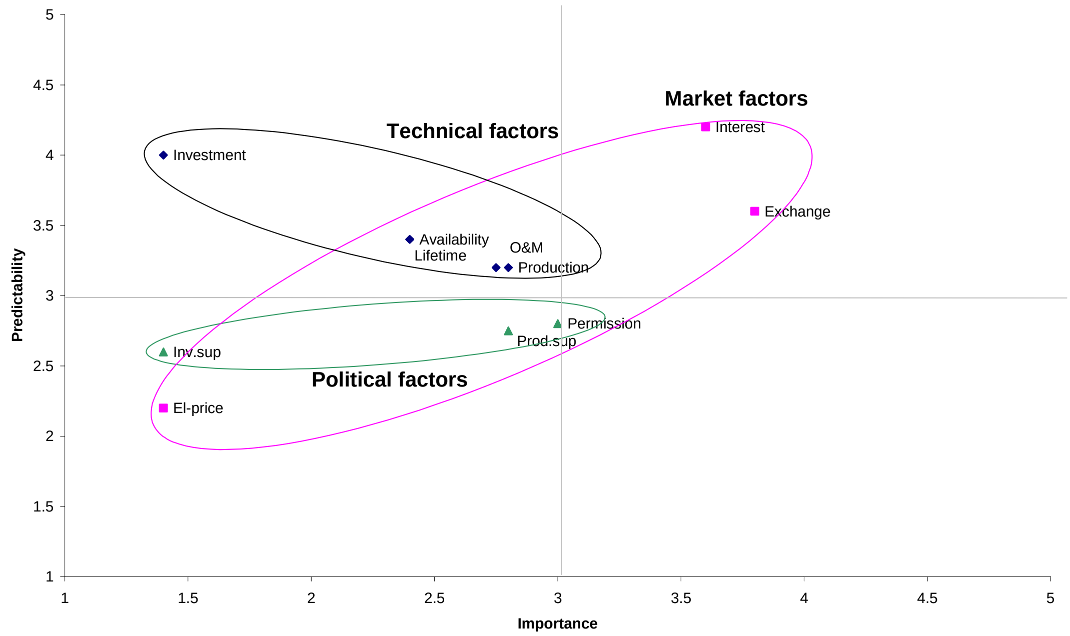

Figure 5.10 *Biomass for all countries*

The technological factors are looked at as low risk factors - indicating that biomass is a more mature technology than PV.

On one hand, most of the biomass responses come from France (80%) who indicates the market factors as negligible factors. On the other hand, a respondent from Sweden indicates that the market factors are risky factors. Especially, the Swedish response indicates the fuel price as a very risky factor. The other responses neglect the risk from the fuel price.

Again, this difference between the interpretation of market and political risks in different countries has to be compared with the actual market situation in these countries. Since the Swedish market is totally liberalised and renewable technologies have their main revenue from the sale of power at this market the Swedish investors are used to market risk. The France situation is the opposite. The France investors are used to long-term purchase agreements and fixed support schemes that in reality overrule the market risk for the investors (see discussion below of market risk).

5.2.2 Discussion of risk factors

As observed above in the analysis of the responses, the interpretations of political and market risks depend on the actual market situation in the different countries - independent of the technologies. On the other hand, technological risk only depends on the technology - independent of the market situation. Based on the observations made in the questionnaire analysis the different risk factors are now discussed further.

Market risk

Market risk factors are: total sales price risk which for TGC systems can be split into electricity price risk and TGC price risk; fuel price risk; interest rate risk and exchange rate risk.

Mature technologies often receive little additional support beside the electricity price. Therefore, the market based revenue; electricity price, TGC price, etc. have a relatively higher share of the revenue than technologies that in addition receive fixed support. This implies that if the immature technologies receive additional support then the market risk is often higher for mature than for immature technologies.

For wind power the responses from the questionnaire clearly identify the electricity price risk as the dominant one. For other technologies the fuel price risk can also be significant, especially for technologies where the switch of fuel type is connected with significant costs.

The exchange rate risk is small according to the responses from the questionnaire. This is partly a consequence of the introduction of the Euro in most of the European Union.

The political versus the market risk depends on the current system, e.g. this is observed in the interpretation of risk connected to investment in wind power in respectively Denmark, the UK, and France (Figure 5.6, Figure 5.7 and Figure 5.8). In Denmark where the support system is connected to the market it is the market factors that are looked at as risky. Political factors are looked at as low risk factors. In the UK and France the interpretation is almost the opposite.

Technological risk

For most RES-E technologies investment costs have very high impact on the profit of RES-E investments, because they are upfront costs. The investment costs for mature technologies have been stable for a couple of years and well known, i.e. there is little uncertainty connected to investment in mature technologies. In other words, even though investment cost is very important for the investment, these factors are looked at as low risk factors. This is confirmed by the responses of the questionnaires.

Less mature technologies, e.g. PV, might not have found the ‘true’ investment cost level yet and unpredictable changes might occur. Therefore, the investment cost for these technologies are more risky.

Political risk
The political risk factors, i.e. the risk of changes in support schemes, and the risk of difficulties with obtaining permits, are seen as important risk factors by many of the respondents. In addition, the respondents state that political risk factors are the most difficult ones to include in the investment considerations, i.e. often they do not include political risk factors when calculating a risk premium. However, if they are regarded important and difficult to include, this does not mean that they are not included in the risk calculations at all. The discouraging effect of lack of trust in the political will or stability in the government is probably not to be neglected.

The planning risk (especially obtaining permits) can be considerable, according to the responses of the questionnaires, and the importance is high. This is connected to the risk of lead-time. There is little connection to the actual investment costs because no major investments are made before necessary permits have been granted. Furthermore the planning risk is partly reflected in transaction costs and lead times.

5.3 Perceptions and experiences from the sector

At the ADMIRE REBUS workshops, held in Denmark, France, Italy, Spain and the United Kingdom in the Spring of 2002, discussions have revealed how investors in renewable electricity and other stakeholders understand and experience investment risk and risk-related costs.

Confidence in the political will
Cases can be found in all MS that point to the dependency of renewable electricity technologies on government support. The result is that investors’ confidence to a large extent depends on the stability and political colour of the government and its credibility. In some countries, the duration even of recently established support schemes is not clear.

- In Denmark, one of the consequences of the recent change of Danish government is that the planned introduction of a TGC system in Denmark has been postponed. This has implied that as long as there are no clear structure and start date of the TGC system, there is hardly any new wind park being planned. The period between the announcement in 1999 of the conversion to a TGC system and its actual launch in 2004 or later is being continuously extended. The result is a lack of transparency, which tends to discourage new participants. On the other hand, large investors already acting on the renewable electricity market say that they can fairly adjust to political uncertainty, without a reduction of their revenues. Their strong lobby position gives them confidence in future political moves.
- In Italy, the situation is characterised by continuous political uncertainty instead of periodic changes. For example, some Italian actors have doubts about that the Italian community wants to pay for reaching the EU target of 25% by 2010. Italian consumers are reluctant to pay more for green electricity and they do not fully trust the origin of the renewable sources. There seems to be not even a national consent about the fact that in the long run, continuing to import a substantial share of electricity from neighbouring countries is more expensive. Additionally, potential investors do not trust the ability of their current government to set the appropriate and legitimate framework to achieve this 25%. The judgement might seem unfair, as Italian policy makers are innovative with regard to the TGC system, but the evidence is that the government does not create enough confidence for investors. The situation is expected to be even more difficult for foreign investors who do not see enough stability in, and commitment of, the Italian government as compared to their own.

- The UK government aims at a ‘low carbon economy’[27]. This among other things means that renewable electricity - a target of 10% in 2010 - and emission reduction targets will be achieved together. This strategy revolves around a tradable certificate system with a renewable electricity obligation and an exemption for the Climate Change Levy. Despite delayed launches in April 2002, respectively April 2001, of the systems the political risk is not considered high. UK actors tend to trust the intentions of their government. The issue lies more in the adjustment that they have to make towards the new situation. In the meantime, the obligation, increasing from 3% in 2002 to 10.4% in 2010, is not expected to be met the first years. Planning authorisations remain a barrier and import is not allowed because of the fear of the market being flooded by imports. The buy-out price (penalty) is fixed at 3p/kWh while the recycling of penalty funds to compliant suppliers increases the value of the green certificates, but this will not make the difference. Summing up the echoes from the UK responses of the questionnaires, there is a trustworthy political will but not all conditions are yet satisfied to really go renewable in the UK.

Fine-tuning

Some actors feel quite uncertain regarding fine-tuning. Fine-tuning means governmental intervention and adjustment in the chosen support system. There are many possible ways to fine-tune both feed-in and TGC systems. Most importantly, this might or might have not been already incorporated in the design of the support schemes. Think of feed-in tariff differentiation like announced abatement in premiums, decreasing proportionally with the site rate of returns. The alternative of unannounced fine-tuning might occur when governments or their administrations become more concerned about controlling investors’ internal rate of return.

They have several ways to intervene in, for example, a TGC market, through fines, caps, etc. If their goal is to follow any fluctuation of the natural remuneration of renewable electricity, one might expect them to often fine-tune its instruments. Although the respondents in France agree with the ultimate aim of a support system to get a renewable technology in the market, frequent fine-tuning makes them nervous and doubtful.

These fears might not affect already contracted projects, but still affect the dynamics within the emergent sub-industry. However, some other investors consider this incorporated fine-tuning as a stronger guarantee of the duration of the feed-in tariff system. It might furnish a better guarantee that the (relatively recently instated) French feed-in systems will endure even if the tendency in Europe is to go from price-guaranteed systems towards market-based systems.

Institutional unsettlement

Many investors feel unsure about the success of their institutional ‘venture’, i.e., the sum total of all administrative permissions and all conditions to obtain and retain the needed financial support. They see policy makers continuously involved with fungibility issues and with fine tuning their support designs. Most investors and stakeholders find it difficult to follow and understand all economic and political developments in the renewable electricity field in Europe. Policies already put in place and those currently in preparation are disparate. It is very demanding to adapt its strategy to newly designed support schemes, and to get a renewable electricity project through new administrations. They ought to share the most obvious political risks with other players subject to them, but often fail to find them or have to pay an unreasonable price. Or they ought to hedge against negative impacts, but they don’t know yet how. They feel alone to face the political and institutional situation that they perceive as unsettled.

[27] In the report ‘Performance and Innovation Unit’ (February 2002).

5.4 How to reduce risk?

5.4.1 Market risk

Market risk will generally refer to fluctuations in the prices of electricity and/or fuel being used by the plant. In general, market risk holds all risks related to the currently chosen market structure. There is a common interpretation of how to cope with market risk with respect to investments in different renewable energy technologies. As for all kinds of risk it is a matter of hedging, i.e. the investor should in one way or the other have a kind of 'insurance' that reduce the risk.

In defiance of this common interpretation there are different ways to cope with market risk. You can either use market mechanisms to reduce market risk, or you can reduce the influence of the market and thereby also the influence of market risk. In both cases the investor transfers the risk to a third party, either by using the markets or with help from the political planner.

In the former case, the investor has to be active by making financial hedging strategies, e.g. forward and futures contracts. In the later case the political planner 'removes' the market risk from the investment by guaranteeing the income, e.g. by long-term power purchase agreements (PPA), fixed feed-in-tariffs, guaranteed loans, etc. In other words, the later case reflects the situation where the market based system is replaced by a political determined fixed price system. In this situation, the market risk is transferred to political risk, i.e. market risks become negligible whereas risk connected to subsidies and other political risk factors become important.

A market based subsidy price is determined by the supply and demand. If there is a domination of a technology, e.g. wind power, then a calm wind year implies a low supply and thereby a higher market based subsidy price. In other words, the total supply of RES-E is negatively correlated with the market based subsidy price, i.e. price and volume risks are negatively correlated, which create a stable income for the producers. This is no longer the case if fixed feed-in tariffs replace the market based prices. Then the volume risk matters more for the investor than it does when the prices counteract fluctuations in the volume.

It is therefore ambiguous if a fixed price system has lower total risk than a market-based system. Therefore, it should be studied carefully before the investor makes lobby work in order to get a change of the subsidy system from a market-based one to a fixed price system.

However, if one recognises the market based system there are plenty of mechanisms connected to this system that can reduce the market risk. In any case, it is important to have good information from and about the power market and power exchanges. In addition, market analyses and other studies can help the investor to become better at predicting fluctuations at the market and thereby reduce the risk. Hedging by financial instruments such as swaps, futures, etc. is effective risk management that uses derivative market mechanisms. These mechanisms are already present at most power exchanges, e.g. at Nord Pool, and they are very used, i.e. the derivative markets are stable and liquid markets at least for products with a time horizon up to 3 years into the future.

5.4.2 Technological risk

Technology risk covers all technical risks related to the costs and availability of the plant. As discussed in previous sections the use of proven and mature technologies implies lower technological risk than using immature technologies. In addition good management and technical skills reduces the technological risk.

Therefore, education, organisation and obtaining of technical skills are some of the overall ways to reduce technological risk. Standardisation and independent tests of the technologies also reduce the risk.

Investment costs

For risk connected to investment cost the following reduce risk:

- Cost studies and proper planning. Gives a low standard deviation for the expected cost.
- Contract management. Transfer the risk connected to fluctuations in investment cost to the other parties of the contracts, e.g. the builder of the plant.
- EPC (Engineer-Procure-Construct) turnkey and equipment supply contracts (or projects). The preferred format for power plant construction is the single source EPC contract. This appears to give the owners/developers a fixed price with an assured delivery date. It has proven to be an attractive format for lenders.

O&M cost

For risk connected to O&M costs the risk can be transferred to a third party by

- outsourcing of O&M costs,
- long-term contracts for O&M costs.

Regarding O&M costs, some constructors of wind turbines are starting to do long-term maintenance contracts that last 10 years.

Annual production

For risk connected to annual production the goal is to predict the annual production to the best extent possible and, if this is not enough, to transfer the risk to a third party. Therefore, there are two ways to reduce the risk connected to the annual production:

- Good wind, hydro, and sun forecasting and measurement.
- Insurance though financial contracts (derivative markets) that insure an expected revenue in defiance of fluctuations in the annual production. The market for these so-called weather derivatives is still in its infancy meaning it is hard to hedge against fluctuations in the annual production caused by fluctuations in the weather.

Availability

Availability of a plant is closely connected to the O&M costs of the plant. The way to reduce risk connected to availability is therefore the same as for the O&M case.

5.4.3 Political risk

Political risk is risk of changes in the system imposed by the government on the owners of capacity. Therefore the political authority plays a key role in reducing this risk. For a single investor this seems hard to do when planning an investment.

However, some of the political risk can in general be coped with. Investors can form organisations that do lobby work on behalf of the investors. For the lobby organisation this requires good understanding of laws and decrees and clear goals. Most of the political risk can be reduced if one is able to get clear, long-term political commitment and legislation. In addition, much political risk can be eliminated through systems based on civil contracts for power rather than relying on future political will.

On one hand, the political risks are for all support systems connected to the future conditions on which RES-E producers that get the support. On the other hand, the political risks differ between the different support systems with respect to level of payments or level of deployment, e.g., in a feed-in tariff system it is the future level of the tariff that matters. In a TGC system it is the future quota that matters[28]. In both cases long-term political commitments reduce the risk and create more stable conditions for the revenue from RES-E and thereby also for investments in RES-E technologies.

A TGC system has another kind of risk, namely the risk connected to a politically determined price cap, i.e. the penalty price and the minimum price. The penalty price is used in order to force the consumers to purchase the TGCs. However, the penalty price also sets a maximum price for the TGC. Likewise a minimum price can be introduced in order to guarantee the RES-E producers a minimum support. In order to reduce the risk connected to a change in the level of the penalty price or the minimum price, it is important to have long-term commitments in this area too.

Political risk can also be connected to permissions from local authorities or councils. It is important to reduce the risk by making the local authorities committed to standardised permission routines with fixed time horizons for handling the applications. The lobby organisations can try to require this. For the risk connected to local areas the investor and/or the organisation can try to get local support from the inhabitants in the municipality. In addition prior consultation with planners and clear guidelines from planners can speed up the permission process.

[28] The risk connected to the TGC price is a market risk and not a political risk.

6. TRENDS IN POLICIES

In all types of investment, the policy framework (i.e., the rules of the game) has a significant impact on the decision to invest or not to invest. In this sense, investment in renewable energy is no exception. Indeed, this sort of investment critically depends upon the existence and the stability of either capacity-oriented support or price-based support schemes. This might be due to the special features of renewable energy involving one-off, capital-intensive investments and with profitability on the part of the investor often dependent upon the application of a policy support scheme.

In this context, and from the point of view of the investor, it is not only the level of present support schemes that matters but, rather, the maintenance of those support levels in time. Indeed, continuously changing support schemes could be perceived as an opportunity on the part of the investor, but reality shows that they mostly imply an increase in the uncertainty and risk levels and, therefore, usually constrain (or delay) the realisation of investments in renewable energy.

Therefore investment today depends on, both, the expectation of support levels in the future (both in the short, medium and long terms) and the time-stability of support schemes. Consequently, as trends in renewable energy investments depend, among other factors, on the expected evolution of support schemes in Europe this issue is worth considering.

With that aim, a survey of policy trends in all EU-15 countries has been undertaken (Uyterlinde et al., 2003). Questionnaires on expected renewable energy policy evolution were sent to renewable energy experts in each Member State (plus Norway), asking them to provide their insights on the expected RES-E policy trends (up to 2030) in their respective country. Results from this survey follow. In a latter stage of this section a closer look at perceptions on the harmonisation process will be provided.

6.1 Expected evolution of renewable energy support schemes in Member States

It is worth mentioning that certain countries are introducing significant modifications in their renewable energy policy support schemes. This is taking place in a broader policy context characterised by the application of the EU Directive on the promotion of electricity from renewable energy sources and by the obstacles encountered in the liberalisation of the EU Electricity sector. Apart from establishing indicative targets for the penetration of RES-E in each Member State, the Directive considers the possibility of harmonisation of the support frameworks in the Member States, if necessary. Currently, each MS implements the policy support scheme that best fits its interest. This provides a dynamic policy context. A general comment, from the responses we have obtained, is that there is a feeling that renewable energy promotion schemes are in a transition stage. The probability of some changes in policy occurring in the future is assumed and is more or less general in all EU countries. This expected unstable policy framework generates a feeling of uncertainty.

In general, changes in support policies could be grouped into two categories. On the one hand, a so-called ‘major change’ might be expected in some Member States. This involves the substitution of a nationally predominant support scheme by a different one (this could involve, for example, the expectation that there would be a change from a feed-in system to a TGC scheme). However, we acknowledge that, in some cases, this might be an oversimplification, as the combination referred above is in fact an interrelation, which means that a change in one measure may involve a change in others)[29].

Major changes

'Major changes' are already taking place in some EU Member States, such as Belgium-Walloon, where a TGC system has already been put in place since October 1st, 2002.

In some other Member States a major policy change is likely to take place, but there is still much uncertainty about that possibility. For instance in *Denmark*, the introduction of a TGC system has been postponed several times, and large uncertainty still exists on the planned introduction in 2004. In the *Netherlands*, the fiscal incentive has partially been replaced by a feed-in tariff scheme (see van Sambeek and van Thuijl, 2003 for details), and further adaptations are imminent[30].

Another example is the *United Kingdom* where, according to the information provided by the expert, current policy is to continue with the RES obligation that obliges electricity suppliers to source an increasing percentage of their from eligible renewable energy projects. The obligation levels set increase from 3% in the period 1 April 2002 to 31st March 2003 up to 10,4% in the period 1st April 2010 to 31st March 2011. However, a Government White Paper on future energy policy is to be published by early 2003, which will consider proposals for increasing the obligation figure for RES to 20% of electricity supplied by 2020. The current legislation defines 10.4% of supplies by 2010 and maintains this percentage to 31st March 2027. From 2020 onwards, the Royal Commission on Environmental Pollution has recommended that the Government considers the implications of sourcing over 50% of electricity from renewable sources by 2050.

Italy is another country where major changes are already taken place and further envisaged for the short-term future. Since the beginning of 2002 the previous feed-in support systems (called CIP 6/92) is not valid anymore and a market system based on a standard green portfolio of 2% (energy from new plants built after March 1999) is effective. A system of TGCs will represent the support scheme and the initial negotiation of the titles should start in 2003 (APER 2002). According to the Italian expert, while in the past priority was given to direct support, both on investment (investment subsidies) and on production (feed-in tariffs), in the future the Italian energy policy for supporting renewables will be more and more addressed towards a strategy combining a command and control with a market-based approach. Indeed, the minimum quota and the TGC mechanism constitute a first fundamental step in that direction.

Sweden also belongs to this group. Introduction of a TGC system is imminent. Starting on May 1, 2003, the scheme will place a quota obligation on all electricity consumers (ranging from 7.4% in 2003 to 16.9% in 2010) although, in practice, the quota will be handled by the electricity distributing companies. Energy-intensive industry is exempted from the obligation in the initial phases of the scheme. Whether or not they will have an obligation in the future is under consideration.

Changes in the longer term

A combination of minor changes in the short term and large modifications in the medium or longer terms is expected in some countries, For example, in *Ireland*, AER 6 was announced on 14th November 2002, setting new indicative targets and prices. The method of competitive tender is expected to be used to meet the targets set for the year 2005 (primarily with onshore

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[29] Furthermore, in some countries policy instruments are exclusive. This means either that the government has made the choice of only proposing one policy instrument, (say feed-in for German wind), or the government give the choice to RES-E generators to choose out of (often two) instrumental options. France proposes wind investors either to make use of feed-in support (for small capacity projects) or to apply for tendering (for larger wind parks).

[30] In September 2003 the government announced the abolition of the fiscal incentive in favour of a complete feed-in tariff system in 2004-2005.

wind). However, the government has announced the intention to release a consultation document in the first quarter of 2003 with the objective to set new targets for the year 2010 for renewable energy and CHP and to examine alternative measures for supporting these technologies.

It is expected that after such consultation, a new mechanism for support will be announced, probably more market oriented. In the opinion of the expert providing the information, some form of advanced feed-in tariff structure will be adopted in the future. Furthermore, he adds that it is unlikely that Ireland will be in a position to participate in a TGC scheme at his point in time “because of market structures and technical infrastructure constraints, although if these constraints are alleviated, Ireland could be expected to participate in a EU wide harmonised TGC scheme”.

No major changes expected
In other countries experts do not expect a major change in the policy support schemes in the short to medium terms. For example, this is the case in *Spain* where a depart from the feed-in tariff scheme is not perceived as likely to happen, in spite of certain statements from public policy officials questioning the level of support for wind.

Austria is a similar case. The feed-in tariff system remains the key policy instrument to promote RES-E and no major change is expected up to 2012. There are two reasons for this, according to the Austrian expert. On the one hand, the system is somehow changing now, in the sense that there is a harmonisation of promotion strategies from provincial level to national level. On the other hand, there has been a negative experience with the tradable green certificate system (for small-scale hydro). From 2012 onwards, a change in policy may take place in the form of joint climate policy and RES-E policy (trading system).

On the other hand, and apart from the above mentioned substantial changes in policy support schemes, some countries are expected to introduce some minor changes related to alterations in the level of support given to RES-E (in terms of price or quantity, depending on the type of support scheme considered). This is the Spanish case, where a drastic change in the RES-E promotion system is not envisaged. The debate about the main promotion scheme (feed-in tariffs) is not taking place in terms of substitution for a quota system (i.e. TGCs) but, rather, in terms of a reduction of price-support levels for RES-E. More specifically, this applies to wind energy. At the municipal and regional levels, there is an increasing awareness of the benefits of RES-E (both in terms of the environment and in relation to employment). As a consequence, more investment subsidies for renewable facilities are being granted.

In *Germany*, there is a mix of uncertainty and continuation with the present system. In August 2003 the Federal Environment Ministry published a new proposal (amendment) for the new Renewable Energy Law. The proposal has been passed to the national ministries with the request for comments. The proposal still relies on the feed in tariff as the preferred instrument to reach the 2010 target. The proposal comes up with more differentiated tariffs, some lower and some higher as in the current law (Uyterlinde et al., 2003). A dramatic change in support policies is not included.

Experts from other countries - *Greece*, *Finland*, *Portugal* and *Luxembourg* - do not expect a policy change (neither ‘major’ nor ‘minor’) in the future.

The above information provides an overview of the heterogeneity of expectations regarding national RE policy evolution. However, this would give an incomplete picture of the uncertainties facing investors (concerning the (un)stability of the policy framework) if not complemented by perceptions on the trend towards harmonisation being set up by the legislation at the EU level. Therefore, it is not only relevant to look at what experts in the Member States think will be the evolution of support schemes in their respective country but, also the perception of the harmonisation process itself. This is provided in the next section.

6.2 Opinions from the sector on the need for harmonisation

Investors in RES-E projects and representatives of utilities, who attended the ADMIRE REBUS workshops, have discussed the concept of harmonisation. Most of them agree that there is a need for harmonisation. However, what they need most is clarity on the *prospects* for harmonisation. The current situation causes a lot of uncertainty. As described above, the policy conditions and support framework for renewable energy are fundamental to the risk and financing of RES projects. Therefore, project developers and financiers prefer stable long-term policy conditions, and in the long run, harmonisation of renewable energy support policies would certainly be advantageous.

Nevertheless, the opinions at the workshops differed. Most participants favour the harmonisation of RES-E support schemes because they expect it will make international investment and trade easier. For example, some Danish attendants state that if support schemes were harmonised, investment decisions would be reduced to only having to look for the best site-installation combinations. French investors point out another expected advantage of harmonisation of support schemes. If policy instruments are already more or less proven - technically and legislatively - abroad, this might facilitate implementation in their own country.

On the other hand, as a more harmonised market is more transparent, some respondents expect it will attract new participants, which might reduce revenues. Moreover, many attendants are still hesitant about harmonisation, as they associate it with the abolition of the familiar feed-in tariffs. Finally, most attendants are not confident that harmonisation of the EU green electricity market will come soon and in an efficient way. They expect the transition period towards harmonisation to be at least 10 years.

Prospects for investing abroad

The audiences expect that harmonisation of the EU market will offer more confidence for investment abroad. On the other hand, some Italian attendants point at remaining barriers related to a ‘nation-first’ sentiment, probably also in other Member States. A related observation is given by wind investors in several countries, who state that often the local developers have already acquired the best sites. Summarising, experience indicates that foreign investors face additional barriers compared to domestic ones and this will probably remain important, regardless of whether harmonisation will actually be realised.

7. FINAL REMARKS

This report focuses on challenges that arise from change of political support systems, lead time and risk with respect to investment in RES-E technologies. We have discussed which tools and strategies can be used in order to overcome these challenges. The report serves as a background report of the main report of the ADMIRE REBUS project (see Uyterlinde et al. 2003). The objective of this report is to elaborate further on the above-mentioned discussions compared to the main report.

A pessimistic reading of this report could give the impression that it is very problematic and risky to invest in RES-E technologies. This could imply that hardly any deployment would be seen. However, the investment in and deployment of RES-E technologies within the EU have never been as large as it is today. Still and in addition to this, if the indicative targets of the EU Renewables Directive are to be reached in 2010, much more RES-E has to be deployed.

European harmonisation of renewable electricity policy is under consideration, which means that current and potential investors find themselves in a transition period. There is a need for harmonisation, but what is needed most, is clarity on the prospects for harmonisation. The current situation causes a lot of uncertainty. Still, regardless of whether harmonisation will eventually occur, experience indicates that foreign investors will have to face additional barriers compared to domestic ones.

Every transition period is one of exposure and arbitrage, especially in the light of the many disparities across the Member States renewables support policies. One cannot expect the market to only wait and see what harmonisation will bring. Instead, opportunities and arbitrage might become in first instance an exacerbating factor leading to more disharmonies across Member States' policies. However, this might, in turn, increase the legitimacy of RE policy harmonisation in the EU.

New investors will enter the RES-E market and the environment at the market will change. The purpose of this report is to give these and other actors a survey of the challenges for RES-E investors at a EU market in transition characterised by a large variety of policy goals and support systems. By recognizing these challenges an investor might be able to take measures that reduce the risk of a failed investment project.

Investors have to face complex administrative procedures in all Member states. These procedures vary according to the country as well as according to technology, which implies a lot of information search for investors. Moreover, delays for obtaining authorisations are not the same throughout the European Union, some countries offering much quicker procedures than others. These delays have a direct impact on the moment when money flows start to come in. A range of factors is causing these lead times, among which local opposition either from local authorities or inhabitants rank foremost.

Investors have the opportunity to smoothen the process by making early contacts with local actors. Projects should be explained at a very early stage in detail to the population as well as to local authorities. Negative reactions can be strong when people feel by-passed. They have to feel their expectations are being taken into account. When this strategy is used, rejections of projects are less frequent. This is not only an effect of diplomatic skills. The higher level of acceptation is also due to the fact that project developers can modify their initial plan so as to make it more acceptable by local actors.

Not only the lead-time and transaction cost, before the production at a new renewable plant can take place, varies. A lot of different factors may create fluctuation in the revenue of an RES-E investment and thereby make it more risky. However, a wide range of measures exists that can be used to reduce this risk.

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ANNEX A TRANSACTION COSTS: DETAILED RESULTS FROM THE QUESTIONNAIRES

44 respondents judged their level of knowledge respectively expertise in the field of lead times and transaction costs. Figure A.1 below shows the self-assessment of the respondents in absolute and relative terms.

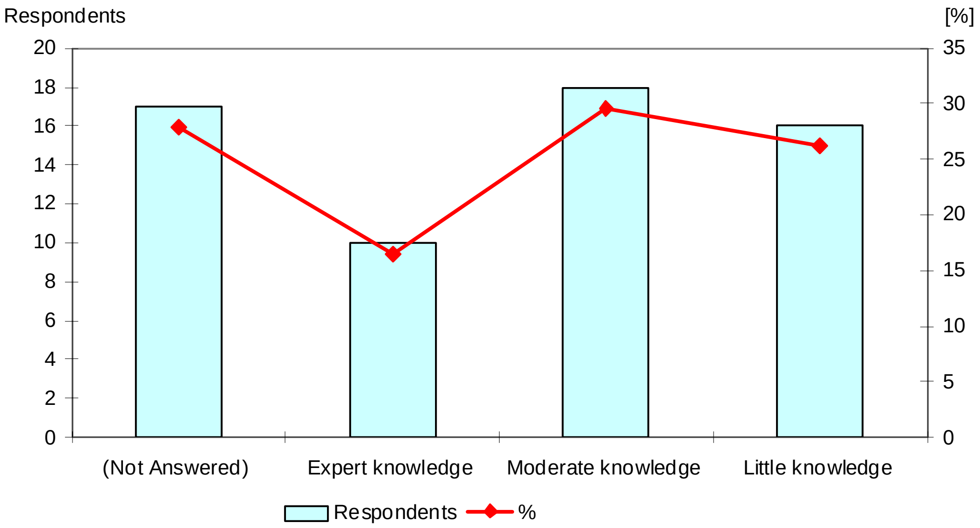

Figure A.1 *Self assessment of investors regarding knowledge about transaction costs*

Among all responds only 13 respondents indicated transaction costs for the search/pre-feasibility and the negotiation/development phases, 12 gave information about the approval phase and 12 indicated costs for the total planning phase. 12 respondents gave their cost estimations in the total production phase and each of the sub phases. Only eight values were given for the total transaction costs of the investment project.

The starting point of the analysis is the calculation of mean values. The values are displayed in Figure A.2. The mean values of transaction costs in the planning sub phases show a relatively equal magnitude of about 5.5% of the total investment. The average of the indicated costs in the total planning phase is approximately 9% of the total investment.

A first consistency check of the responses shows a discrepancy between the cumulated values of all three sub phases and the indicated total value of the planning phase. The same discrepancy can be found in the production phase. While the cost estimation of the total phase is about 7% of the total investment, the cumulated transaction costs of the sub phases roughly twice as high (sum at roughly 16%, monitoring 5.4%, enforcement 6,2% and adjustment 4.5% of total investment). A comparison of indicated measures of the whole investment project with the sum of the total measures of the phases results in smaller differences (13.5% vs. 16,0%). A possible explanation might be that respondents tend to overestimate the magnitude of transaction costs of each sub phase.

A summarisation of the average values of all six sub phases would result in a total value of roughly 32% of total investment. The analysis given above implies the comparability of sub phases and the aggregate phases.

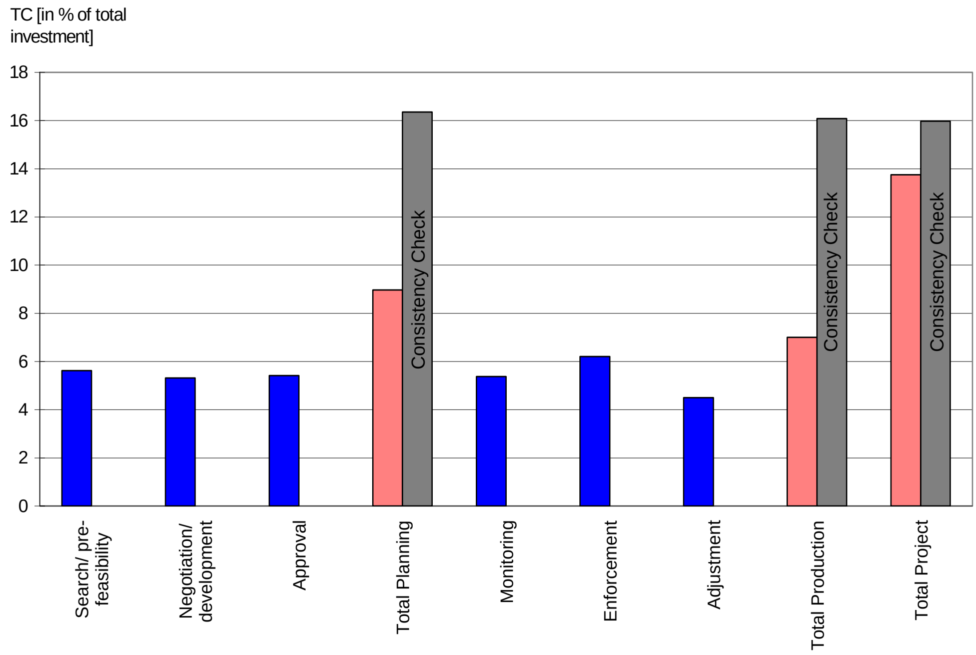

Figure A.2 *Mean values of different phases*

The given values scatter to a large extent. Figure A.3 displays, again, the mean values and, additionally, the bandwidth of measures indicated in the questionnaires. Maximum values of both sub phases and aggregate phases reach magnitudes of up to 30% of total investment costs. Figure A.4 describes mean values and the bandwidth without extreme values (dropping maximum and minimum values). Although this approach further reduces the database, it has an effect on the bandwidth of some values. While the scattering of values diminishes for the total production phase and the sub phases negotiation/development, monitoring and adjustment, the bandwidth of the remaining phases still is on a rather high level.

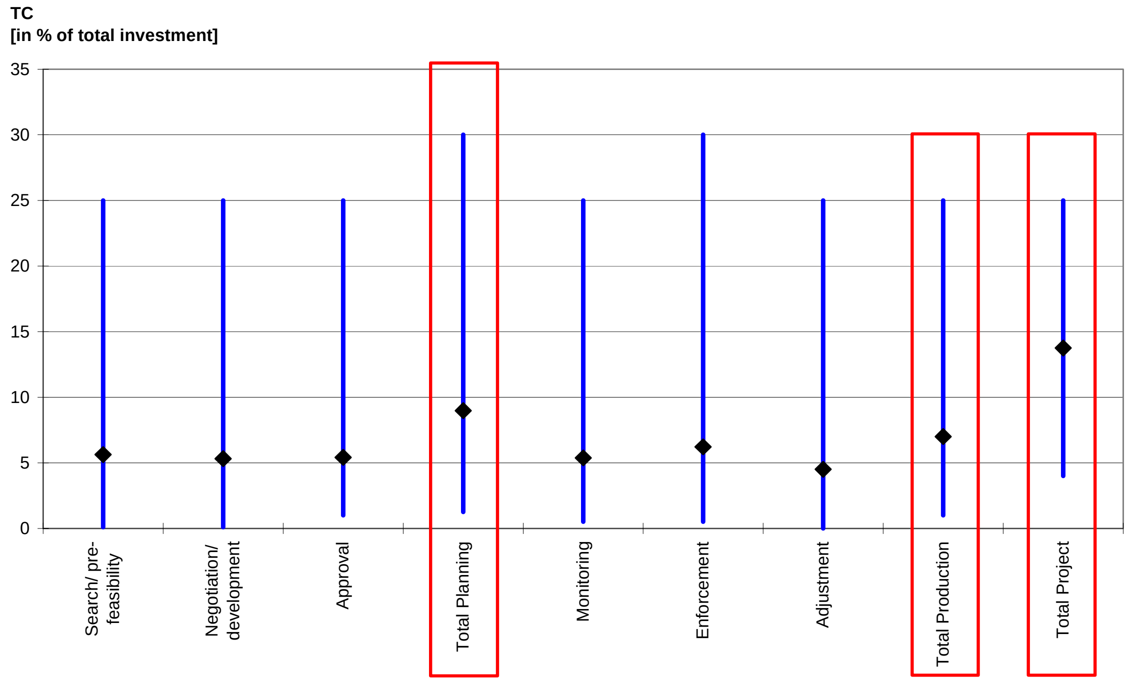

Figure A.3 *Bandwidth of indicated costs (all respondents)*

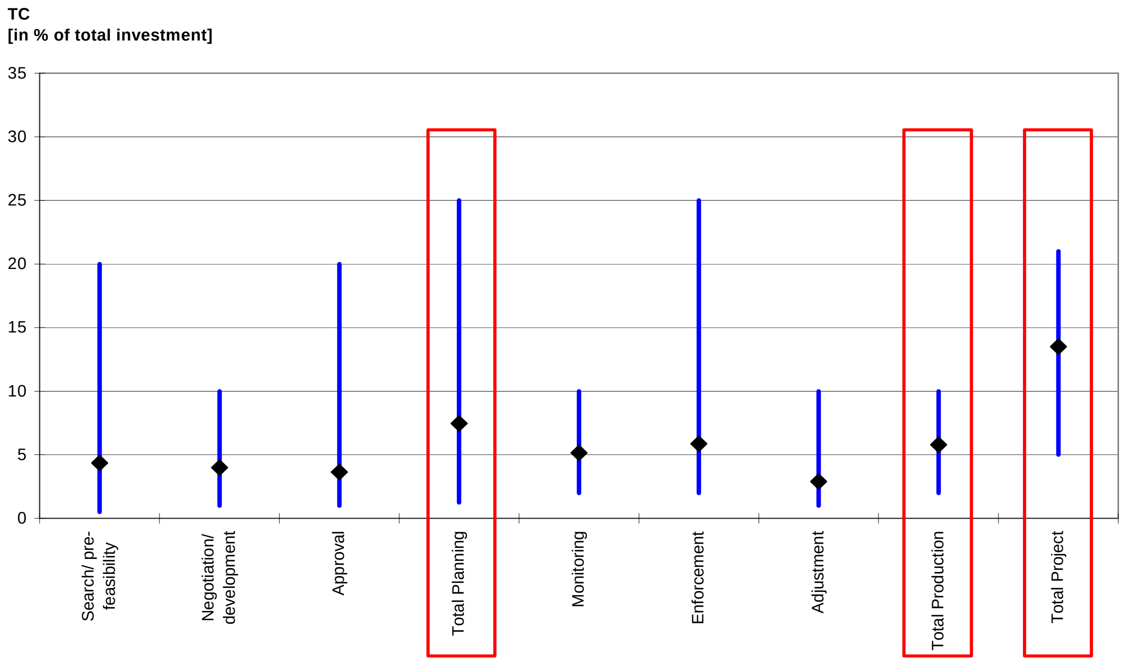

Figure A.4 *Adjusted bandwidth of indicated costs (without extreme values)*

Only 15 respondents gave information about failed projects but this issue seems to be relevant. The values range from 1 (successful project per planning phase) up to 10 (planning phases for one successful project). The average value has a magnitude of 4.2 planning procedures per successful project. Again, we excluded the extreme values, which results in an average of approximately 3.2 planning phases per successful project. Combined with the information about transaction costs in the planning phase, failed projects may significantly raise costs for the successful projects.