Establishing the investment case
Wind power

April 2014

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1. Foreword

In recent years investors all over the world have paid increasing attention to the renewable energy industry.

This trend has translated into rapid renewable energy commercialisation and considerable industry expansion, of which the wind industry is a good example. According to Clean Energy Trends 2014, investments in new capacity of wind energy increased from approx. USD 4bn in 2000 to approx. USD 59bn in 2013. While annual investments in 2013 were down from USD 74bn in 2012 the compound annual growth rate (CAGR) was 23% in 2000-2013. Annual investments in the industry are projected to grow even further up to USD 94bn by 2023.[1]

With a total of 35 GW installed wind energy capacity in 2013, annual installations were down from the record-high 45 GW in 2012. Of the 35 GW, China added more than 16 GW, whereas Europe accounted for 12 GW of new capacity. In 2013 global installed wind capacity reached a total of 318 GW.[2]

The International Energy Agency (IEA) estimates that total onshore wind capacity will reach 546 GW by 2020 and 923 GW by 2035. Offshore wind capacity will add 175 GW to this, and the wind industry's share of global energy generation will increase significantly up to 2035. By then it is expected that wind energy will account for approx. 7.3% of total power generation, up from 1.6% in 2011.[3] On a longer horizon, IEA has updated the 2050 target of total global power originating from wind energy from 12% to 15-18%.[4]

The development in the wind industry is still dependent on public subsidies and political willingness to support the industry. On the 2020 horizon action plans have been put in place globally. The EU has ambitions of 20% renewable energy by 2020, whereas China and Japan have specific plans for increasing wind energy capacity. The US has a target of 80% renewable energy by 2035, which includes 54 GW of offshore energy by 2030.[5]

The aim of this paper is to promote diligent business case analyses. This is in the interest of all industry participants since it will give decision makers a better understanding of wind farm economics, profit opportunities and risks related to wind investments.

[1] CleanEdge, "Clean Energy Trends 2014"
[2] Global Wind Energy Council, "Global Wind Statistics 2013"
[3] International Energy Agency, "World Energy Outlook 2012"
[4] International Energy Agency, "Technology Road Map 2013"
[5] International Energy Agency, "Annual Report 2012"

2. Introduction

This paper addresses how the main elements and considerations regarding wind investments are built into an investment case analysis.

The aim of every investment case analysis is to assess project viability, project uncertainty and to ensure that all relevant factors have been considered prior to final investment decision (FID). Such analyses provide decision makers with a better understanding of wind farm economics, profit opportunities and the risks of wind investments.

Throughout the paper we will address 5 key steps when assessing a wind investment case. In section 3 we discuss the initial considerations which an investor should make when deciding if a given wind investment is desirable. In section 4 we provide a more detailed description of the specific inputs required to perform the investment case analysis. In section 5 we take a view on the risks and uncertainties related to the investment case, whereas in section 6 we describe how the relevant elements are combined into an investment analysis. We end this paper with section 7 where we discus some potential pitfalls when valuing a wind project.

From our point of view, the main challenges in performing a wind investment case analysis are assessing the expected level of energy production and energy prices as well as the future political regime. Despite their uncertain nature we will demonstrate how these elements can still be implemented in the investment case in a useful way.

Throughout the paper we will present relevant examples and figures for key input parameters which are based on benchmarks from more than 80 operating wind farms and more than 40 international market studies on wind farm economics as well as on our extensive experience from acting as financial adviser in more than 30 wind projects.

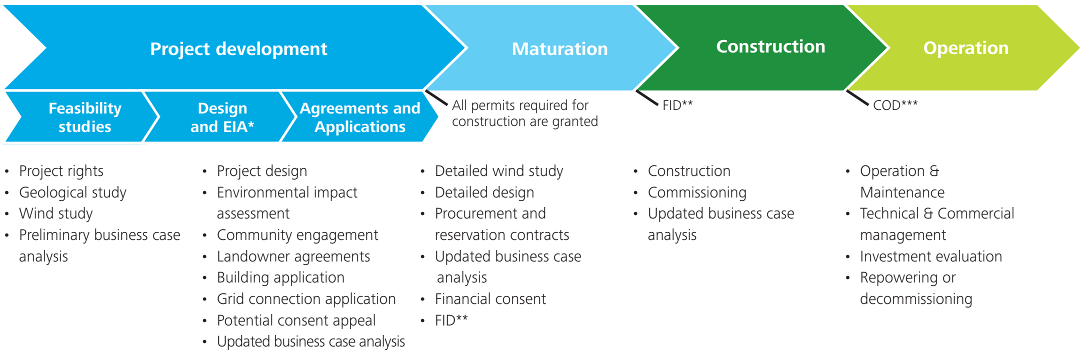
We acknowledge that wind projects are subject to site and project-specific characteristics and that in a specific project input parameters must naturally be adjusted according to the ongoing development of the project, such as contractual agreements with suppliers or power buyers.

Consequently, this paper merely describes how a wind investment case should be addressed in order to fully assess the characteristics of risks and returns. We also illustrate how to apply benchmark data for a preliminary valuation during the initial project development stages and emphasise key input parameters and uncertainties to which the investor should pay additional attention.

3. Framing the investment case

The process of developing wind projects typically lasts 3-5 years for onshore projects and 5-10 years for offshore projects from project initiation to the wind farm has been commissioned. This is followed by 20-30 years of operations during which the up-front investment is recouped. The figure below illustrates the main steps of developing a project from idea to a commissioned wind farm.

Project lifecycle of onshore wind farm assets

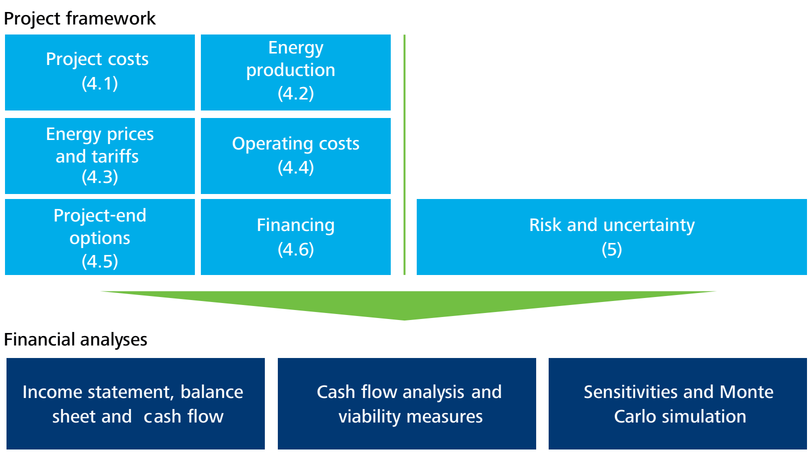


Note: * Environment Impact Assessment, ** Final Investment Decision, *** Commissioning Date
Source: Deloitte analysis

The development stage is characterised by establishment of the project layout on basis of for example environmental, geotechnical and wind studies. The turbines should be placed such that soil and wind conditions favour lower capex and higher energy production. Furthermore, a preliminary financial model is built in order to assess if the investment case can be expected to be economically feasible. Often a financial adviser is appointed early in the process to bring in experience and expertise with assessing the investment case and enhance the probability of successfully undertaking the project.

During maturation wind studies and wind farm design are refined in order to secure optimal layout of the wind farm. Procurement contracts on construction elements and turbine service are conditioned on the construction start or the commissioning of the project. New insights on production, capex and opex feed into a refinement of the financial model which in turn supports financial consent from investors and lenders. After FID the project goes into the final stages of the project lifecycle, which includes construction and afterwards operation.

As the financial model is continuously developed from the early stage of a project and refined and adjusted throughout project development, it is important to make solid considerations about the structure of the model already at an early stage of development. When performing a wind investment case analysis we turn to 7 key elements that need to be evaluated in order to properly understand the investment base case and conduct sensitivity analyses. The figure below illustrates the 7 key elements that frame the investment case analysis.



Source: Deloitte analysis

In the following section we discuss how to incorporate each of these 7 elements into a financial analysis of a wind investment case in order for the financial model to reflect sound considerations about the financial robustness of the investment case.

4. Detailed considerations

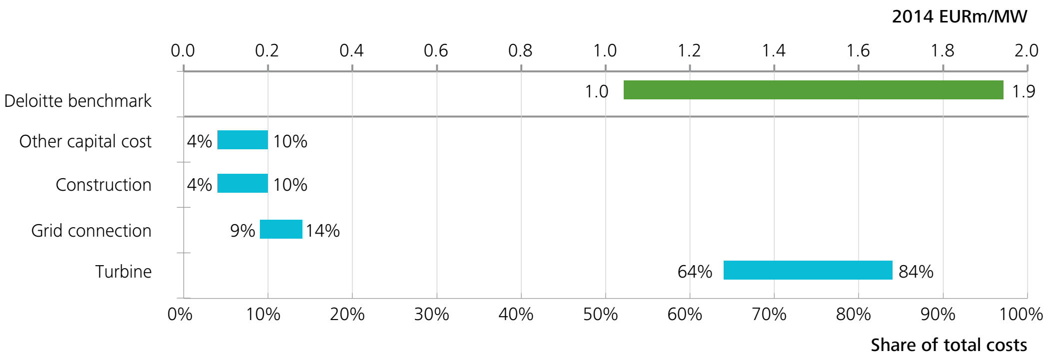
4.1. Project costs

One of the main considerations when developing a wind farm is overall project costs and how these are split between main cost elements. In general project costs will accumulate until the turbines are commissioned, and while costs during project development and maturation are rather insignificant, the construction phase by far accounts for the largest cost accumulation in developing a wind farm. This is due to the large costs of turbine, foundation and transmission assets compared to the relatively small costs of environmental impact assessment, wind studies, financial analyses and consenting costs.

As illustrated below, there are significant variations in total project costs for onshore wind farms. Besides differences in year of data sampling these variations may be due to several effects, including soil conditions, applied technology, cost of transmission assets, infrastructure and local costs. At some sites there is already a functioning infrastructure, which makes the need for e.g. additional roads smaller. Also, project costs can be affected by project profitability as turbine suppliers often increase prices on projects where they anticipate that returns are high and competition is low.

In the figure below we have provided a range for total onshore project costs (green bar) based on market reports and our own experiences with wind farm economics. The blue bars illustrate how total onshore project costs may be split between 4 main cost elements.

Total project costs – onshore

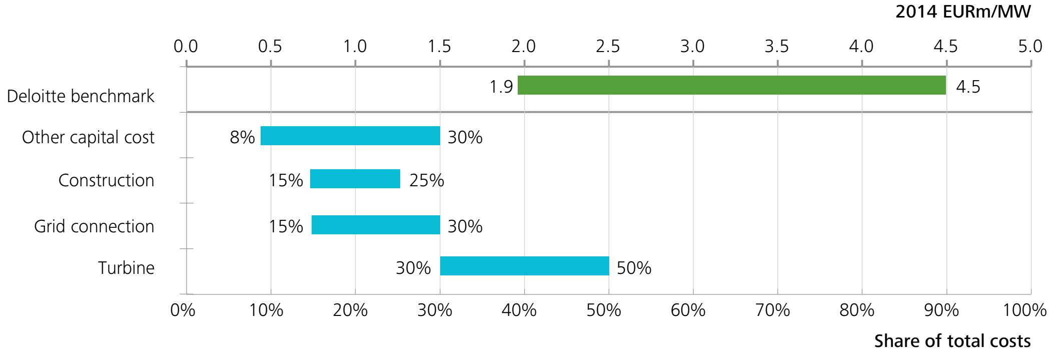


Source: Deloitte analysis based on more than 40 international market reports and on our experience with onshore projects. Main ressource on split: IRENA 2012

Project costs also vary with project complexity. As offshore projects are generally more complex than onshore projects they are also typically 2-3 times more expensive per installed MW. In offshore projects, the turbines tend to make out a smaller part of total project costs as all other components become somewhat more expensive.

It is the costs of foundation, grid connection and construction in general that are greater in offshore projects relative to onshore projects. We have provided a range for total offshore project costs and a split between main cost elements in the figure below.

Total project costs – offshore

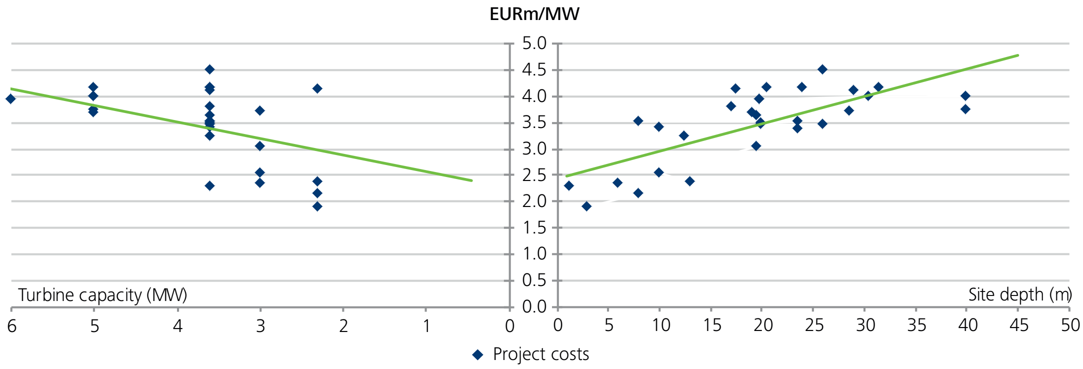


Source: Deloitte analysis based on more than 40 international market reports and 34 offshore projects commisioned/commisioning after 2010 as well as our experience with offshore projects. Main ressource on split: IRENA 2012

Based on benchmark data we have been able to perform various analyses on project costs of offshore wind farms. For example we find that larger turbines and greater site depth have increased total project costs per installed MW historically.

This is supported by the figure below which shows project costs for 34 offshore projects worldwide (blue dots) and compares it to sea depth at the project site and size of the employed turbines. The green trend lines illustrate increasing project costs with increasing site depth and turbine size, respectively. The latter might seem counter intuitive and could in part be explained by the fact that larger turbines may comprise new and relatively unproven technology. The positive relation between project costs and site depth may be explained by the fact that greater site depth requires larger and more complex foundations to be built which in turn leads to higher project costs.

Effects of turbine capacity and site depth on total offshore project costs



Source: Deloitte analysis based on more than 40 international market reports and 34 offshore projects commisioned/commisioning after 2010 as well as our experience with offshore projects. Main ressources: Deloitte analysis, LORC and 4COffshore

In general, it is the perception in the market that applying larger turbines will decrease total project costs due to fewer foundations and installations per installed MW in the future. In addition, innovation and standardisation are expected to help the industry in realising its cost reduction targets of up to 40% for offshore wind energy.

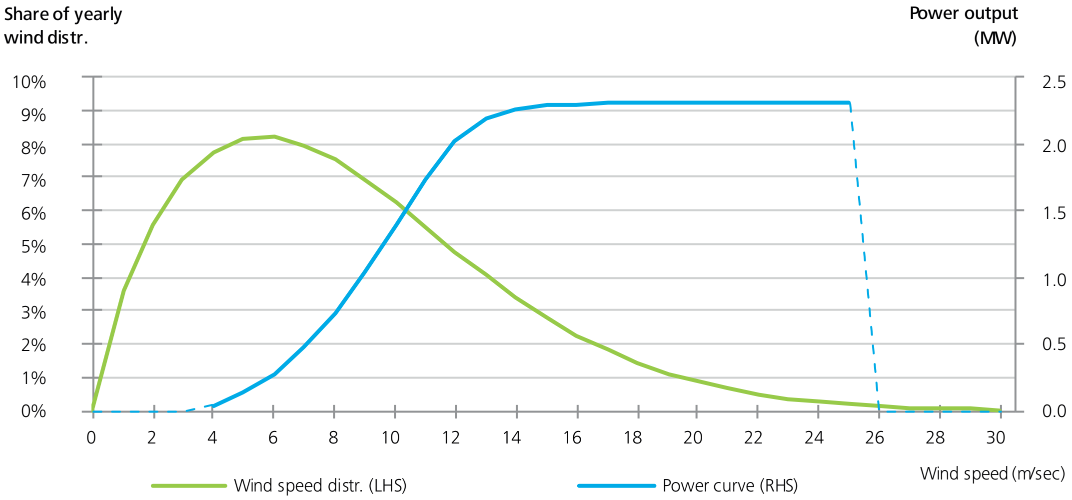
4.2. Production

Another important input parameter is the expected power production. As sufficient wind speeds at the project site are the main drivers of wind energy production and of wind park revenues, the understanding and forecast of wind become essential. Therefore, a lot of effort must be put into assessing the wind energy resource at the given project site. This is done by performing a wind study, which over a period of typically 2-5 years measures the wind in for example 10-minute intervals and on the basis of these measurements describes the speed, direction and density of the wind on the project site.

The collected data are used to model the expected annual energy production (AEP) from the wind park, which is done by taking into account wind speeds and directions as well as air density, temperature and humidity.

To transform wind energy into power, the wind turns the rotor blades of the turbine, which yields a given power output based on the wind speed and the turbine model. This power output is described via the turbine's so-called power curve. Therefore, by application of the distribution of wind speeds, it is possible to calculate the expected production from the wind park.

Wind distr. assumption and turbine choice



Source: Deloitte analysis

A power curve is characterised by a cut-in and a cut-out wind speed. The cut-in wind speed is the level at which the turbine starts to produce power, while the cut-out wind speed is the level at which the turbine stops producing power due to the risk of damaging the turbine from excessively high wind speeds. In order to optimise production, the chosen turbine should therefore match the forecast wind speeds so that the turbine rarely stops producing power due to either too low or too high wind speeds.

It is therefore important to carefully assess which type of turbine that creates the most optimal production characteristics in terms of expected production and production variability.

In order to illustrate how wind speeds transfer into expected energy production and how production uncertainty is quantified, we have provided an example in the figures below. The leftmost figure shows an expected distribution of wind speeds with a mean of 8.5 m/sec (light-blue line) and a power curve for a 2.3 MW turbine (dark-blue line).

In our example the combination of the expected wind speed distribution and the turbine specific power curve yields an expected yearly gross production (P50) of approx. 8,000 MWh. To estimate the net production potential losses deriving from for example wake effects, electrical losses or from the fact that turbines will not be able to produce energy at all times due to for example planned maintenance must be taken into account.

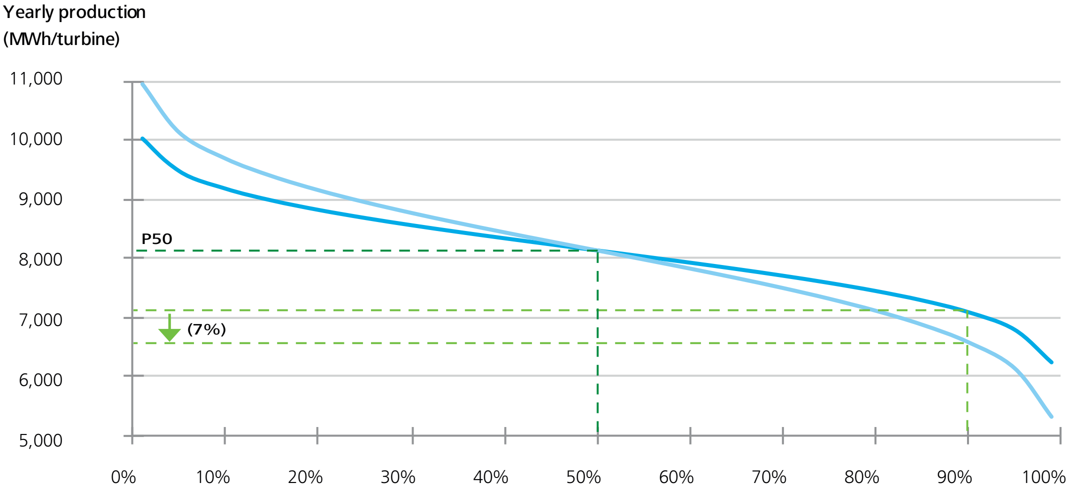
Understanding the expected production and its limitations

While a wind study results in an expected energy production from the wind farm, this estimate is exposed to uncertainty. This uncertainty can be significant and is therefore important to take into account when assessing the energy production of a wind farm.

Therefore wind studies often quantify the uncertainty in terms of standard deviations, which allow for the modelling of expected production based on a statistical approach and lead to a more qualified assessment of expected production and production uncertainty.

The expected yearly production of a wind farm is called the P50, and this is the production level which is exceeded with a probability of 50%. Analogously, the wind study tends to state P75 and P90 production which is interpreted in the same way as the P50, and which can be used to evaluate the uncertainty in the production forecast. If a project developer wants to illustrate a conservative production estimate the P90 could be applied. We have added production uncertainty to the AEP estimate above. This results in a curve which on the horizontal axis illustrates the probability of exceeding the yearly energy production stated on the vertical axis. We have illustrated the P50 and the P90 by the dark green and light green dotted horizontal lines.

Wind distr. assumption and turbine choice



Source: Deloitte analysis

A closer look on production uncertainty

As mentioned above, a wind study often states the uncertainties related to the estimated P50. We define these uncertainties as wind variability and model uncertainty.

Wind variability relates to the fact that yearly mean wind speeds at a given site change will differ each year due to variation in meteorological conditions at the site and the nature of wind intermittency. Yearly energy production will therefore also vary each year. While the realised yearly production is likely to vary around the expected production, which will be constant, it is important to understand that production will not be constant during the operational life of the wind farm.

We therefore consider wind variability as a year-on-year variability. Such variability also applies to factors like changing average wind directions and production losses caused by for example icing on blades and availability of the turbines.

Taking into account the year-on-year variability allows us to estimate changing P measures over time, as the statistical properties of random variation allow the average of all year-on-year variability to decrease when evaluated over a longer horizon. This means that the 1-year P90 will be lower than the 20-year averaged P90, and we therefore consider this uncertainty as a dynamic uncertainty.

Model uncertainty relates to the uncertainty of the parameters estimated based on the wind study. Consequently, while wind studies are often based on very complex models, there is a risk that they contain estimation errors, such as measurement errors and/or model errors.

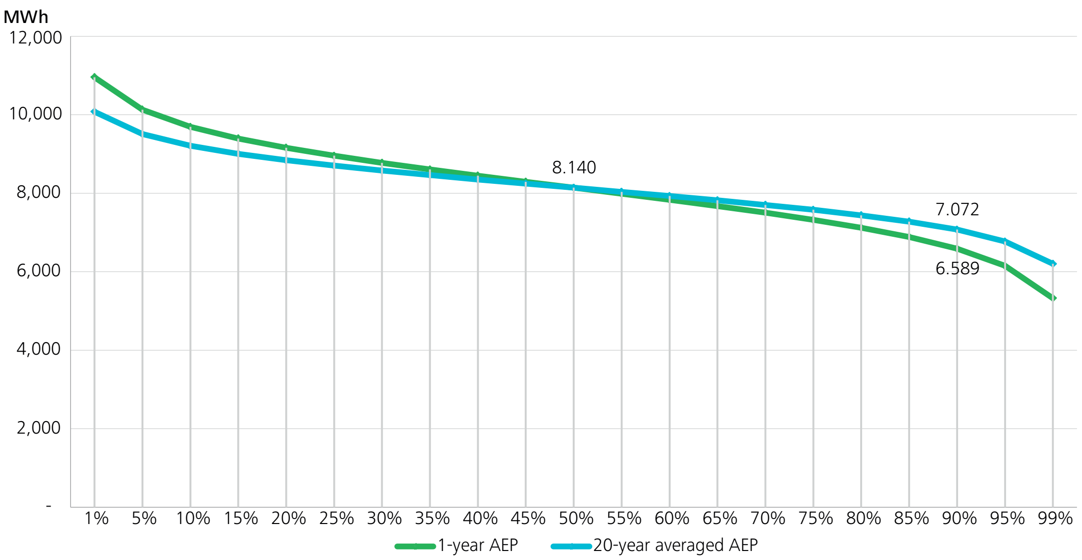
Measurement errors include that measured wind characteristics may not be correct due to for example dysfunctional measurement instruments or incorrect calibration of these. Model errors for example relate to the risk that measured historical wind conditions are not representative of the future wind conditions.

Furthermore, the wind study may be wrong with respect to assessing the effect a turbine has on the turbine specific production of the turbine behind it, which is called wake effects. The size of the wake effects is affected by factors such as wind speed, wind density, turbulence and distance between turbines, meaning that wake effects may be larger when the wind is coming from a direction in which turbines are located closer to each other.

We consider model uncertainty as a static uncertainty, which means that it is fixed over time. This implies that if the wind study has underestimated the true wind average speed or wake effects for the first operational year, it will be underestimated in all years. Consequently, taking wind study uncertainty into account, we reach static P75 and P90 measures that are fixed over the life of the project.

In the figure below we illustrate how different P measures are affected by how wind variability is taken into account (whether wind variability is averaged or not). The blue line illustrates production uncertainty when all production uncertainty is considered on an average basis, while the green line illustrates production uncertainty when wind variability is based on short-term uncertainty.

AEP uncertainty



Note: Example is based on a 2.3MW turbine
Source: Deloitte analysis

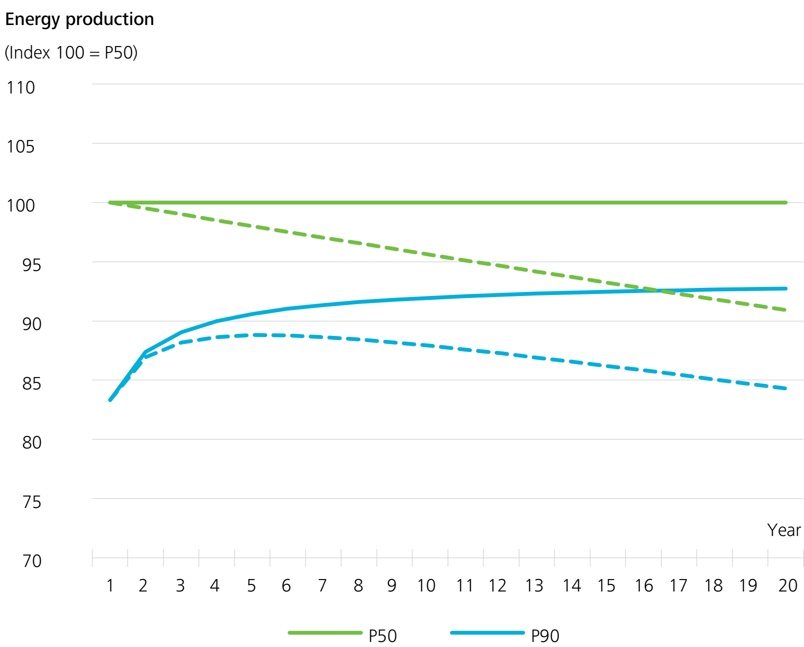
At the P90 level the difference in AEP is approx. 7%, which shows that production uncertainty is greater in the short term relative to in the long term due to averaging effects of wind variability in the long term. In section 4.7 we illustrate how wrongful assessment of production uncertainty can significantly affect the understanding of project viability.

Additionally, there may be other time-related factors that affect the expected production level of a wind farm such as degradation of blades as a result of wind and dust tearing the smooth blade surface into a more rugged surface, which in some cases lead to a decrease in turbine efficiency of 0.5-1% per year.

However, by planning specific maintenance of blades, this degradation can be avoided at the cost of an increase in operating costs. Also, the expected availability of the wind farm tends to decrease during the operational life due to more frequent maintenance and turbine break-downs.

The figure below illustrates how different production levels depend on the horizon that it is viewed upon due to the levelling out of year-on-year wind variability as well as the assumption applied regarding degradation. The solid lines show the relation between the production measure and the assumption of no efficiency degradation, whereas the dotted lines show how production level decreases over the operational life due to a yearly efficiency degradation of 0.5%.

Short and long term P50 and P90 under no and 0.5% yearly efficiency degradation effects



Source: Deloitte analysis

The arguments outlined in this section illustrate and underpin how expected production is related to uncertainty. In particular we have shown that separating production uncertainty into static uncertainty and year-on-year variability lead to a more detailed view on assumptions about expected production levels.

4.3 Power prices and subsidies

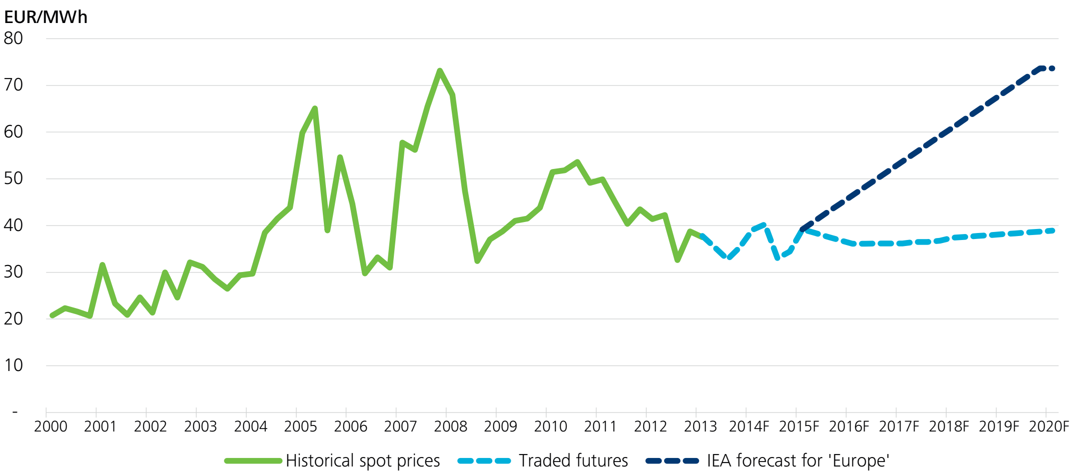
Combined with the level of production, power prices affect the profitability of a project directly, and it is therefore necessary to make sound reflections on the power price forecast.

A lot of information can be found in short-term futures and forward markets if power contracts are traded frequently. However, in the long term, markets often become illiquid and forward prices may reflect inflation expectations rather than the expected development of the market price. Fortunately there are companies and organisations that specialise in performing fundamental analyses where forecast of supply and demand are combined into a long-term price forecast.

There are significant variations in power prices across continents and countries, which are often divided into different price areas. However, integration and interconnection cables between price areas are increasing, which will result in smaller price differences between countries and regions.

The figure below shows historical power prices from EEX in Germany which are closely interrelated with the rest of Central Europe. The blue-dotted line between 2014 and 2016 shows forward prices on EEX. From 2016 we have extended the forward curve to 2020 (light-blue dotted line) and as an alternative illustrated a price forecast published by IEA 2020 (dark-blue dotted line).

Example of historical and forecasted power prices



Source: EEX.com and EIA, "World Energy Outlook 2012"

Obviously, the 2 forecasts illustrated above display a large divergence in the expectations for power prices. Therefore, the profitability of a project can depend critically on the applied price forecast, for which reason sensitivity analyses on the development in power prices are an important part of assessing the robustness of an investment case. Often the investment case will be less exposed to market risk as most projects are eligible for fixed subsidies for a given period.

Subsidies may constitute a substantial part of wind farm revenues. Consequently, in the initial phase of developing a wind farm project, the prevailing subsidy terms should be investigated in order to assess the impact and importance of subsidies on the investment case. The terms for receiving subsidies, the size of the subsidy and the period in which a project is eligible for subsidies are important issues.

We note that while some subsidies are contingent on the level of the power price, others are pre-determined payments unconditional on the level of power price, and therefore power price forecasts only become relevant when subsidy payments end at some point during project life.

We have illustrated how different countries have structured their incentive schemes. While there are many different subsidy schemes for wind energy we only show the 3 main subsidy scheme structures: Feed-in-Tariff (FiT), Renewable Obligations (RO) and Tax credits. A FiT may be a constant tariff paid per MWh produced in addition to the market price or a fixed payment regardless of the level of the power price. Also, the FiT can be capped when the market price and subsidy combined reaches a certain level, which for example is the case in Denmark and the Netherlands.

ROs often take form as a general obligation forced upon power utilities to source part of their consumption from renewable sources. The scheme can be combined with renewable energy certificates, which are traded in a secondary market and which power suppliers must buy in order to prove their support to renewable energy generation. This is for example the case in Norway, Sweden and the UK.

Tax credits may take form of for example income tax credits where some or all installation costs are tax deductible from future income streams as a rebate on payroll taxes under installation of the wind farm or as an import tax credit.

We note that even though some of the countries in the table above apply the same main subsidy structure, there are significant variations in the size and duration as well as the underlying conditions for being eligible for subsidies between the individual countries. Also incentive schemes are subject to changes and may differ between onshore and offshore wind farms.

Overview of subsidy schemes in different countries

Country	FiT	RO	Tax credits
Australia	✔	✔	✔
Canada	✔	✔	✔
China	✔	✔	✔
Denmark	✔		
Germany	✔		✔
Ireland	✔		
Italy	✔	✔	✔
Netherlands	✔		
Norway		✔	
Sweden		✔	
UK	✔	✔	
US	✔	✔	✔

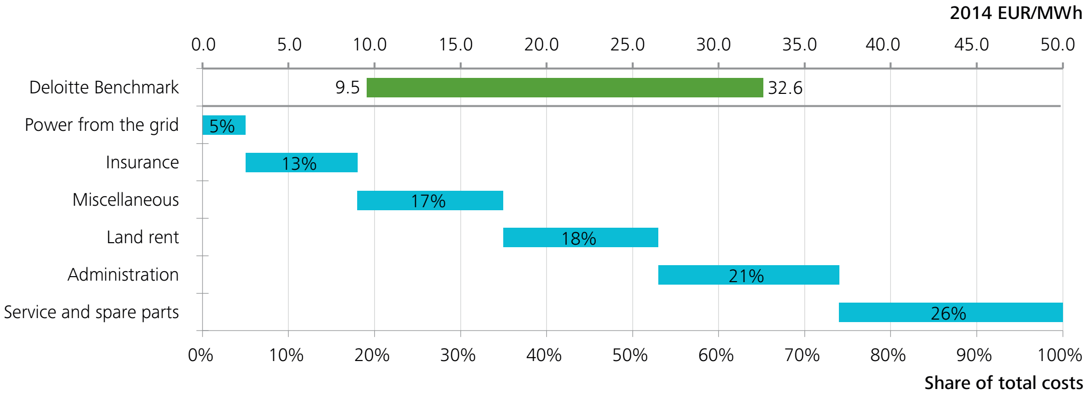
4.4 Operating costs

In our experience, onshore and offshore wind farms operate with a rather high EBITDA margin of approx. 60-90%, which reflects the low marginal cost of producing power from wind turbines. In this section we discuss and provide benchmarks for the different categories of operating costs (opex).

Some operating costs such as land lease, insurance, management costs and maintenance costs (O&M) can be fixed at a yearly amount. However, depending on the contractual structure of the project, some of these costs may also vary with production on a per-MWh basis or as a percentage of revenue which will form a hedge on operating costs.

In the figure below we have provided benchmark data for the level of operational costs (opex) for an onshore wind farm and also provided a split into the main cost drivers.

Total opex and opex break-down – onshore

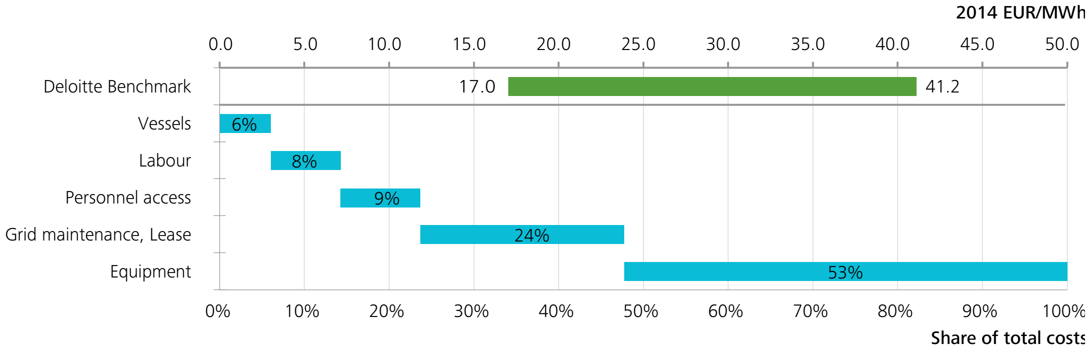


Source: Deloitte analysis based on more than 40 international market reports and on our experience with onshore projects. Main ressource on split: IRENA 2012

The main elements of opex include costs for O&M and asset management. O&M will often be covered for approx. 5-10 years by a service contract with the turbine supplier. However, in the current market, we observe service contracts with durations of up to 15 and 20 years. It is important to consider costs not covered by the contract and potential changes in operating costs after expiry of the service contracts. Over the operational life the turbines will be worn down and additional costs can apply due to more frequent maintenance, breakdowns, etc.

Opex for an offshore wind farm is somewhat higher than for an onshore farm due to greater costs of accessing and maintaining turbines. Harsh marine environment can also increase the failure frequency of some components. Offshore wind farm opex level and split are illustrated in the figure.

Total opex and opex break-down – offshore



Source: Deloitte analysis based on more than 40 international market reports and on our experience with onshore projects. Main ressource on split: IRENA 2012

As the offshore industry is immature relative to the onshore industry, we expect opex per MW for an offshore wind farm to decrease as the supply chain is industrialised and as learnings from early offshore wind farms transfer into the operations of new ones. Furthermore, we expect the employment of large turbines to put a downward pressure on offshore opex.

In general, opex may vary significantly between projects depending on mainly price of the service contract and the land lease. For a preliminary purpose it is often possible to benchmark estimates and ranges of main opex elements. However, as the project progresses more detailed information and estimates are required and should also be available. Some opex elements may be pegged to revenue or production to form a hedge on profit margins.

In addition to the opex elements described above, tax considerations are also an important part of investment case analyses. The characteristics of tax modelling will vary across countries and projects. In particular it is important to consider how payable tax differs to accounting taxes, as the former one will have liquidity effects, whereas accounting taxes may contain elements that have no liquidity effect.

4.5 Project-end options

As a wind farm project reaches the end of its operational life, various real options exist. These include decommissioning, repowering or overhaul of the wind farm and will be dependent on the terms of the land lease.

If the lease is coming to an end, with no option of renegotiating, decommissioning is more likely. However, with an option to extend the land lease, a large overhaul can extend the project life for some years. If the land lease can be renewed for a longer period, repowering may prolong the project life and represent a new profitable investment case as costs of development, infrastructure, towers, etc. have already been incurred.

The costs of repowering relate to the specific turbines that are installed, whereas the costs of overhaul depend of the magnitude of the overhaul. Decommissioning costs relate to the applied type of foundation and the number of turbines. Decommissioning costs also tend to relate to total project costs, which mean that decommissioning offshore wind farms are more expensive than onshore wind farms, in particular due to the extensive need of specialised vessels.

Finally, it is important to apply a reasonable assumption regarding the useful lives of the turbines, which are often set at 20-30 years. However, as for other assets, the useful lives also depend on the wear of the assets, and for wind farms the useful lives depend directly on the energy production and the chosen level of concurring maintenance during the operational period.

4.6 Financing

During the maturation stage of the project, the capital need must be determined and the optimal capital structure must be defined by way of analyses. A project can be financed either by using the owners' own balance sheet as collateral or through a project company, also referred to as a special purpose vehicle (SPV). It is more common that SPVs are established as many wind projects require significant investments and as the SPV structure opens for the possibility of obtaining non-recourse debt financing. I.e. financing is obtained on the project's ability to raise debt on its own merits as the SPV has its own revenues and balance sheet.

The maturity of loans depends on the project finance structure, but often maturities of 10-15 years post-completion are obtainable at a borrowing rate of approx. 4.5-6% in the current markets, depending on the instalment plan and the risk of the project. Instalment plans may take the form of annuity, serial or bullet loans. Also they may include an option to sculpture instalments via for example a cash sweep or a revolving credit in order to accommodate potential liquidity issues that may arise as a consequence of the variation in revenues. Such variations may be caused by the year-on-year wind variability and in particular by power price fluctuations if the project does not have a PPA.

When performing investment case analyses it is also important to test the robustness towards different capital structures, i.e. levels of debt and equity. Based on our experience, we see a relatively high gearing in wind projects of about 50-70% debt financing, where onshore and offshore projects are typically in the upper and lower range, respectively. The difference is due to the larger risk in offshore projects, and the larger equity capital requirements which increase offshore projects' need for secondary equity investors such as large institutional investors.

When considering how to finance the wind farm project it is also important to consider different types of investors. In Europe lenders to wind projects among others include governmentally owned investment funds like the European Investment Bank, Nordic Investment Bank and Green Investment Bank. Commercial banks have also provided debt capital to wind farm investments via single bank, syndicated and club bank loans. In addition, export credit agencies are also commonly engaged in financing of wind farm projects.

The possibility of non-recourse debt in an SPV incentivises equity investors to pursue a high gearing of the project as it limits the lenders' claim to the project assets in case of default. A higher gearing would decrease the requirement of equity injection and enhance equity returns at the cost of a higher risk of not meeting debt service requirements.

Lenders are interested in fixing cash flow streams and reduce the risk of their relatively low-return investment. Therefore the level of gearing is often limited by lenders or governments which may impose certain covenants on the debt package.

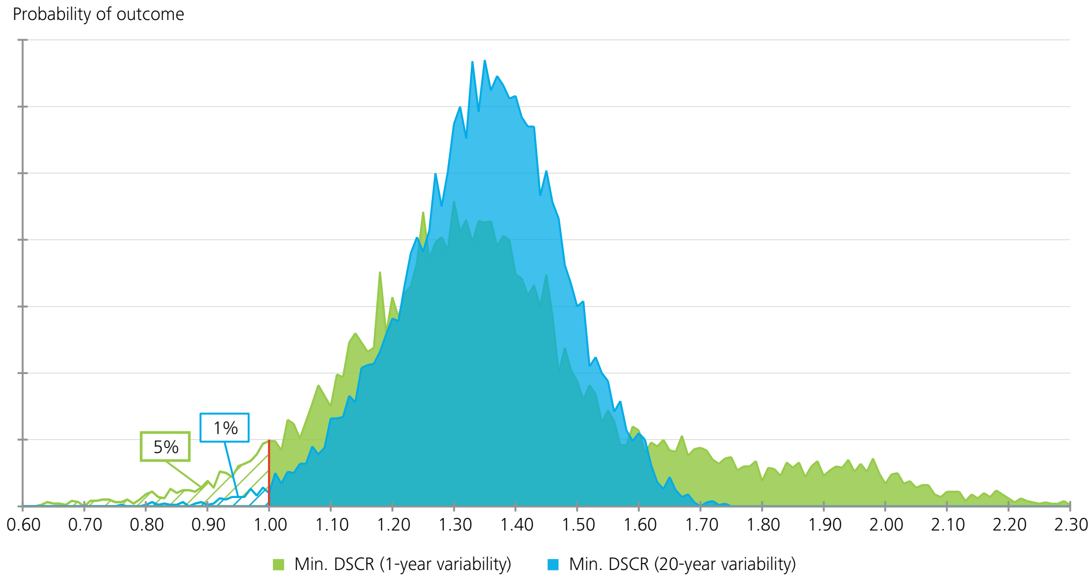
Covenants are restrictions that specify certain limitations on for example the size and the use of the loan. Therefore using project financing means that you need to deal with the banks' requirements. DSCR (Debt Service Coverage Ratio), which expresses the project's ability to pay interest and instalments from its cash flows, is one of the widely applied covenants. In addition to the covenant described above, lenders often require a cash reserve account of 6-12 months of debt service (interest and instalments) and a maintenance reserve account equal to 6 or 12 months of O&M costs. We often also see that banks limit the use of project proceeds, for example by restricting cash flows from being paid out to equity investors before some or all debt has been repaid.

In addition to covenants lenders require comprehensive financial due diligence and stress testing of project assumptions in order for them to gain comfort in the project's viability. In relation to this, identification and understanding of project risks are essential as unidentified risks may potentially jeopardise the entire project.

Assessing a minimum DSCR distribution and the probability of default

In the current debt markets, a project's covenant with respect to minimum required DSCR is approx.1.2x-1,4x during the maturity of the loan at a P90 production level and dependent on whether it is an on- or offshore project. With regard to a project's minimum DSCR, this is often considered in a static model using a 10- or 20-year P90 production measure. However, as we show below, this approach has some limitations when assessing the risk of breaching covenants in the short term. In the figure below we illustrate a project's minimum DSCR under a simulated production. The blue area shows the distribution of the minimum DSCR observed when using 1-year wind variability, whereas the green area shows the distribution of a minimum DSCR when using 20-year wind variability. The hatched areas in the left side of the figure show the simulated outcomes where the minimum DSCR was below 1, and therefore indicate outcomes where the project may default on its debt. It is also relevant to investigate the probability of breaching debt covenants (such as a minimum DSCR of 1.3x), as this may impose additional costs or/and restrictions on project owners.

Minimum DSCR distribution under 2 different wind variability assumptions



Source: Deloitte analysis

As mentioned in section 4.2, the yearly production uncertainty when based on a 1-year wind variability measure is greater relative to a yearly production uncertainty based on a 20-year variability measure. This is exemplified in the figure above by the hatched green area being more than 4 times larger than the hatched blue area. In other words, when project viability is assessed using a 20-year wind variability, the project will default with a probability of 1%, whereas it will default with a probability of 5% when using the 1-year wind variability.

We have seen that wrong assessment of the production risk during the first years of operation and consequently misunderstanding the probability of default have caused that some projects in recent years have faced financial difficulties due to "bad wind years". This can either be handled through lower gearing or by means of changing the conditions and covenants on the loans.

As leverage is usually greatest during the first years of operation, it becomes highly relevant to understand the short-term production risk. Based on this understanding and thorough analyses in general, it will be possible to structure an optimal debt package that matches the risks inherent in a project.

A decision of using project finance should be made by the investors early in the project development as a lot of the value created from the project finance discipline is created at an early stage, when designing the contractual structure and negotiating contracts.

The use of external funding can help improve the risk discipline for the project as more external parties looking at the contracts and project structure often result in more informed solutions. Also, banks and lenders often have a more specific focus on the potential downside scenarios which may prove to be helpful for assessing project viability. As non-recourse finance is a unique discipline and approach to project risks, it often can be a good idea to use experienced advisers with specific knowledge of the debt industry and great experience in project financing.

5. Investment case certainty

While some of the key input parameters of the investment case have been discussed in the previous sections, many risks and uncertainties are still left to be evaluated. The figure below illustrates the risks inherent in developing a wind farm project and how some of these risks relate to specific stages of the overall project development, whereas other risks are inherent throughout the entire project life.

Overview of general and stage-specific risks

Planning	Construction	Operational	Decommissioning
• Ground conditions • Wind conditions • Wake loss conditions • Site availability conditions • Grid connection conditions • Environmental conditions	• Availability of necessary infrastructure • Performance of suppliers and contractors • Weather conditions • Commodity prices	• Technological performance • O&M costs • Weather conditions • Electricity prices • Regulatory climate	• Decommissioning costs • Environmental impacts

Political

Economic

Financial

Others

Total project risk

Source: Deloitte analysis

Stage-specific risks include the risk that capital spent on feasibility studies and environmental studies is not recouped due to rejection of the project. It also includes the risk of turbine breakdowns and bad wind years which can affect production and also project viability. These risks mainly concern the planning and operational stages. In the figure below we describe some further examples of common stage-specific risks.

Description of stage-specific risks

Planning	Construction	Operational	Decommissioning
• Expensive site feasibility studies which may result in the site being rejected • Many wait-and-see investors who do not invest due to risk of losing development costs and due to little benchmark data • Site feasibility studies accounts for 3-7% of total project costs • Important that these studies are conducted properly in order to successfully pursue further investments • Construction of electrical infrastructure is often delayed	• Bad weather may increase downtime and shorten construction time windows • Competing for same suppliers as oil and gas companies increase risk of bottlenecks • For offshore wind farms, installations require vessels which are in short supply • Cable installations can be damaged from rocky seabed, dragging anchors and strong water currents • Improvement of infrastructure and supply chain is needed to mitigate construction risk	• Energy production is affected by technological performance via downtime and turbine breakdowns • Uncertainty related to operation of large wind turbines which is still a very immature market • Interconnection between production risk and financial risk	• Lack of experience with this stage exhibits uncertainty with regard to environmental impacts such as seabed damage and bird migration • Little experience with the process and costs of decommissioning • Political risk in potential changes in the decommissioning responsibility

Source: Deloitte analysis

Regarding the general risks, which are relevant to consider and assess during the different stages, these often display more externality than stage-specific risks and are therefore harder to assess and in some situations more difficult to mitigate.

As such, they include economic and financial risks, which are typically quantified and assessed via the financial model, but they also include risks and uncertainties that can be more difficult to quantify which are still relevant to consider when making the final decision on an investment case.

In the figure we list some of the most relevant risks that are present in the current market – these examples include both unquantifiable risks, such as risk of changes in government support, and the risk inherent in new technologies and environments.

Most project risks are known in advance and can therefore be mitigated if properly assessed and handled in due time. As briefly described above, it is also our experience that bringing in external debt financing can be helpful in this assessment.

Uncertainty intervals for onshore stage-multiples

Political risk	• Governmental support and subsidies can affect whether the project is feasible • Duties and customs on construction elements affect the quality of construction elements and the country of sourcing • Basel III and Solvency II can be subject to changes (this also transfers into financial risk)
Economic risk	• Energy demand and electricity prices may fluctuate widely, but are often fixed through long-term PPAs • Competition with other power sources with special focus on LCOE • High inflation may carve out the value of cash flows relative to up-front investments • Commodity prices risk that may increase overall project costs
Financial risk	• Lender appetite determines if lenders compete to offer the best loan terms • Liquidity in project finance markets of syndication and securitisation markets has reduced in the aftermath of the financial crisis and the credit crisis • Production risk due to wind variability imposes both liquidity risk and credit risk
Other risk	• Lack of qualified workforce may affect the quality of the wind farm development, construction and operations • Technological advancements may increase the opportunity cost of capital and decrease the value of the wind farm • Weather conditions in the development, construction and operational stage • General risk related to a rather immature offshore industry

Source: Deloitte analysis

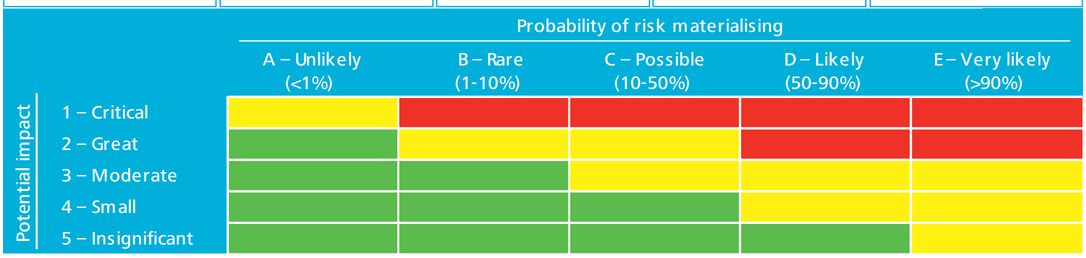
Based on our experience it is often a good basis for the development process to have a risk workshop, where the individual risks of a project are identified and discussed amongst the different stakeholders in the project. As these stakeholders might change during the development process, it can be a good idea to have several workshops throughout the process.

The main purpose of having a workshop is to identify and discuss each risk as well as determining the likelihood of occurrence and the financial impact. The participants in each risk workshop should include all key stakeholders in a project at a given stage, ensuring an adequate, thorough and objective evaluation.

We often find that risk workshops that are somewhat structured and operationalized through for example a risk matrix as shown below are more valuable for the future process. It facilitates mapping of the identified risks according to the magnitude of the potential impact and the probability of the risk materialising into an unwanted outcome. The matrix can further be applied for prioritising the identified risks and determining de-risking actions on the most urgent risks.

Identifying and prioritising risks by use of a risk matrix

Risk phase	Risk type	Likelihood	Financial impact	Risk owner
• Planning • Construction • Operations • Decommissioning • Not stage specific	• Political risk • Economic risk • Financial risk • Other risks	• Unlikely • Rare • Possible • Likely • Very likely	• Insignificant • Small • Moderate • Great • Critical	• Equity sponsors • Lenders



Source: Deloitte analysis

In combination with the financial model, this way of assessing and mapping project risks provides a sound basis for understanding the relation between a project's risk and return which are the 2 key elements when deciding whether to invest.

Therefore we advise proper facilitation of a risk workshop in order to ensure that all risks, their outcome probability and financial impact are assessed correctly.

6. Gathering the threads – assessing the wind investment case

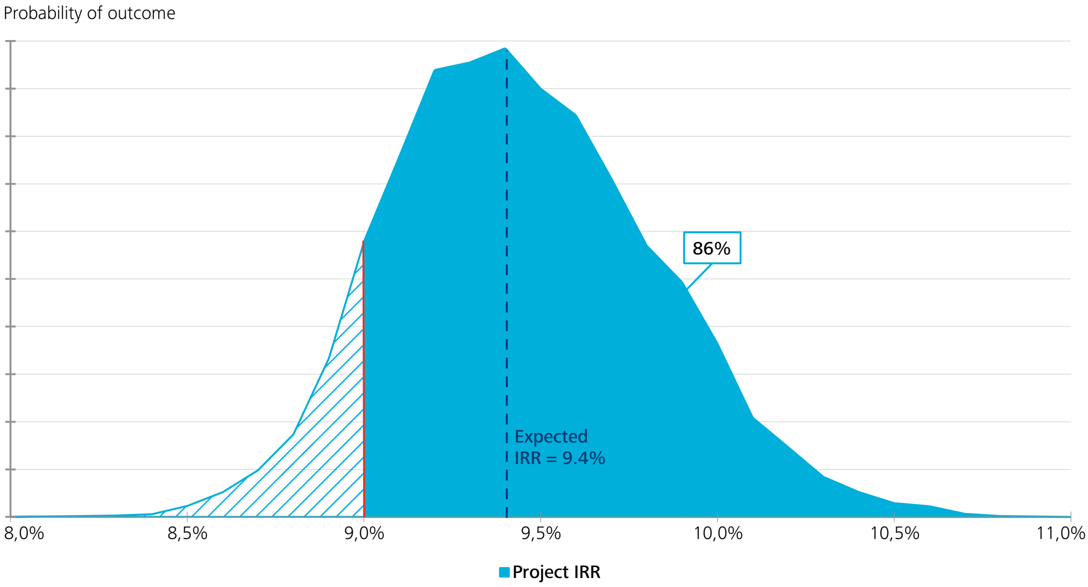
Having performed the steps and analyses described in sections 4 and 5, a financial evaluation of the investment case can now be conducted. The evaluation is partially based on outputs from the financial model, the contractual structure for the project and on the outcome of the risk assessment process. Key figures like DSCR and project IRR (internal rate of return) are the main figures to investigate, whereas equity IRR is the most interesting measure for equity investors. As noted above, these figures are also often subject to requirements in order for the project to undergo approval of financing.

The final model should include modelling of income statement, balance sheet and cash flow statement as well as relevant key figures and a potential valuation of the project.

Investments in wind projects are as other projects subject to uncertainty. Consequently, financial performance will be uncertain. Static wind business case models that only represent expected outcomes will therefore often have some limitations with providing the information to support informed investment decisions. Conversely, a scenario-based or a simulation-based approach provides better insight into the investment case and enables decision makers to make better investment decisions. We describe this approach in detail below.

The figure below shows output from a simulation model prepared for a wind project in the form of the distribution and the probability of various IRRs at project level given yearly variations in energy production. The hatched area illustrates the simulated outcomes where project IRR is below the required rate of return. In our example, the wind project will generate an IRR that exceeds a required return of 9% with a probability of 86%. Adding additional uncertainties to the investment case, such as varying power prices, risk of capex overruns, opex variations, etc. may widen the distribution of project IRR and move the expected IRR.

Project IRR distribution under production uncertainty



Source: Deloitte analysis

The advantage of a simulation model is that it assigns a probability to specific outcomes rather than just providing some pre-defined punctual estimates for the outcome as it is the case with static models.

Furthermore, the effect of changes in project finance structures, production guarantees or service agreements can be tracked all the way to the shape of the IRR distribution. Thereby it becomes clearer how a change in assumptions affects the risk and rate of return on the project enabling decision makers to directly assess the impact when changing and narrowing in project assumptions throughout the development of the project.

Given variations between wind projects' risks it is our experience that the discount factor varies among projects. The figure below illustrates our experience from different ranges for post-tax required returns for on- and offshore wind projects depending on whether the project is in the developing- or the operational phase for most developed countries.

Project post-tax IRR requirements for on- and offshore projects

Project stage

	Pre-operation	Operation
Onshore	7.0-9.5%	5.5-7.0%
Offshore	8.5-11.0%	6.0-7.5%

Project complexity

Source: Deloitte analysis

Besides the project stage and the complexity of the project, the required rate of return on a wind farm investment depends on multiple factors, including the track record of the applied technology, market risk, the contractual structure of the project, the climatological variations at the project site and the political climate in the country in which the project is realised.

The above range may therefore not be representative for a specific project and will be subject to changes over time.

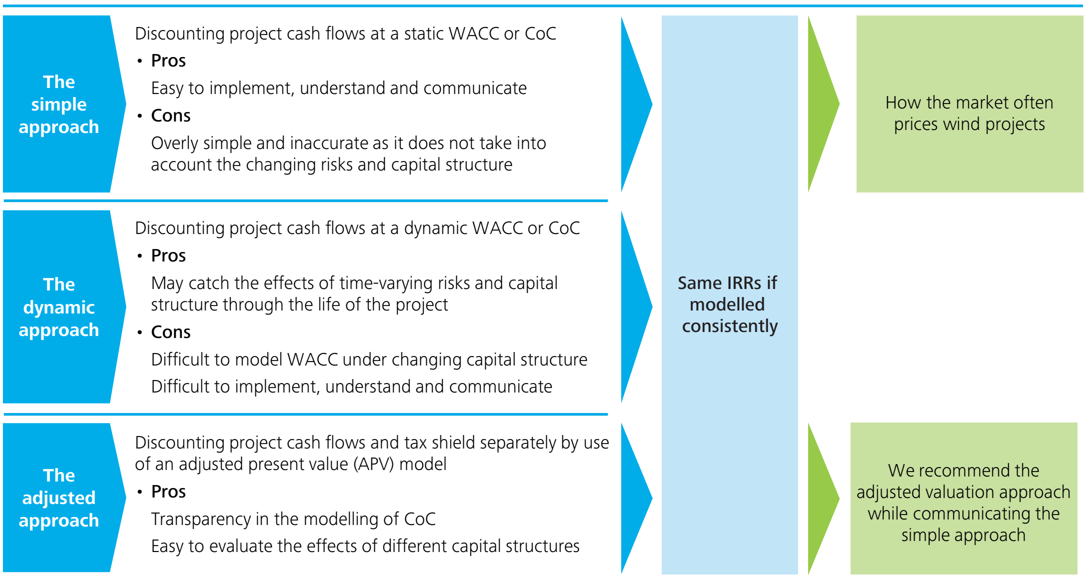
7. Valuation pitfalls

When performing a cash flow analysis on a wind project there are certain pitfalls that should be avoided. In particular the cash flow analysis should take into account the varying capital structure of the project as well as the time-varying risk of the project. These characteristics mean that the required rate of return is not fixed over the life of the project. Due to varying capital structures we recommend using an adjusted present value (APV) approach which can take this dynamic into account by valuing the tax shield from interest payments separately.

Apart from the capital structure, the required rate of return will vary over time due to changes in the project's risk profile. For instance, when maintenance contracts or PPAs expire, the project will be exposed to somewhat more risk, and the investors should require a higher return at this stage in the project.

However, a dynamic required rate of return can be difficult to model and communicate to the relevant stakeholders. Below we illustrate and describe pros and cons of different approaches to handling the required rate of return when performing a cash-flow analysis. The simple approach is the easiest to implement, understand and communicate, but it comes at the costs of greater imprecision and uncertainty.

Overview of 3 different financial modelling approaches



Source: Deloitte Analysis

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