Greenpeace

A financial and economic comparison of coal, gas and wind as options for Dutch electricity generation

26 March 2008

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26 March 2008

Dear Ms. Baretta,

I am pleased to present our final report on the economic assessment of three different generation production options in the Netherlands. This report has been drafted in accordance with our engagement letter dated 4 December 2007.

The economic assessment we have executed relies on price projections for the Dutch electricity market provided by our sub-contractor – IPA Energy + Water Consulting Ltd. ("IPA"). In this report we summarise the main IPA findings. For a full discussion of data, assumptions and results we refer to the final IPA report dated 20 March 2008.

We stress that PwC has not performed an audit, verification or independent validation of the aforementioned data and thus does not undertake any responsibility or liability and does not give and must not be interpreted as to be giving any (explicit or implicit) assurance for the accuracy or the completeness of the data. This report does not constitute investment and/or legal advice. Furthermore, we draw your attention to the following important comments regarding the scope and process of our analysis.

Proper and balanced conclusions can only be drawn from this report when it is read as one document. Reading parts of the analysis separately could lead to different conclusions that do not necessarily reflect the conclusions that would be drawn when this report is read as one document. Using different data sources and different underlying assumptions could lead to different – and equally valid – outcomes and therefore different – and equally valid – conclusions.

Nothing from this report may be published without prior written consent. For other terms and conditions we refer to our engagement letter and General Terms & Conditions.

Yours faithfully
PricewaterhouseCoopers Advisory N.V.

Professor Dr. Jan Willem Velthuijsen
Partner

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Section 1
Executive summary

Executive Summary (1/3)

Introduction and background

- In the last two years a number of energy companies have publicly announced plans to invest in electricity generation capacity in the Netherlands. These plans come at turbulent times. Both the Dutch and international energy markets are at strategic crossroads.

- Causes for this turbulence include, inter alia, increasing oil and gas prices and the geopolitical risks associated with gas supplies, the increased attention for climate change, the ongoing discussions at both a national and EU level about the price and allocation mechanism of CO_2 permits, the recent increase in global coal prices, and the implementation of governmental financial incentives for renewable options (e.g. wind and biomass) to realise national and EU renewable energy targets.

- Investments in power plants are capital-intensive and have a long lifecycle, therefore the impact of the choice of a particular fuel type will have a long-term impact on the environment and the overall costs to supply power. Given the expectation of new capacity investments, Stichting Greenpeace Nederland ("Greenpeace") is interested in getting a more in-depth and independent financial-economic insight into the business fundamentals that might drive these investment decisions.

- Greenpeace has therefore engaged PricewaterhouseCoopers Advisory N.V. ("PwC") to compare – from an economic and financial perspective – two alternatives against a "standard" coal-fired power station. These two alternatives are (i) gas-fired and (ii) wind-powered generation.

- In our assignment we have engaged IPA Energy + Water Consulting Ltd. ("IPA") to provide independent forward curves for fuel and electricity prices in the Netherlands. IPA has published a separate report titled "Forward curves for Dutch electricity prices for the period 2007-2030". This report discusses, inter alia, the underlying assumptions, four scenario's, data sources and the economic model of the Dutch electricity market that have been used by IPA for their projections of fuel and electricity prices.

Fundamental assumptions impact key findings of financial economic analysis

- Our analysis is based on assumptions that could affect the outcomes. Different assumptions could therefore lead to different – but equally valid – conclusions. We stress that our findings are based on the next fundamental assumptions:

  - The technical and cost assumptions of the three different production options for our analysis have been based on IPA input combined with a high level survey of relevant publicly-available sources. Proven technology is the basis for our analysis. Innovations which might occur in the years ahead are not included in the analysis. We stress that investments and returns with alternative fuel options (such as dual firing) or alternative technologies may differ.

  - We assume that there are no location issues, such as limited or restricted access to fuel supplies, planning and permission issues, or other realisation costs.

  - We have performed our financial economic analysis based on a "pure" power producer point-of-view. We therefore do not take into account potential synergies from value chain effects, e.g. owning particular fuel sources.

  - Our economic analysis focuses on a theoretical 1MW capacity power supply. This approach enables a like-for-like comparison of the three production options. In a competitive market the results of our analysis can be translated to full scale production options.

Government policy appears to be the key driver in our economic analysis of energy generation production options

- Our analysis demonstrates that current government policy with regard to the electricity market, has an important impact on our key findings. The two major governmental policy instruments in this respect are the European CO_2 emission trading scheme and the new Dutch stimulation subsidy for renewable energy ("SDE").

- We assume that both current policy instruments will exist during the horizon of our analysis (2030). Other views on either the stability or the future design of these policy instruments could influence the outcome of the analysis.

Executive Summary (2/3)

- The price development and allocation mechanism of CO_2 permits is a key driver behind our findings. In our analysis we assume that (i) CO_2 permits will continue to have a positive price, and (ii) producers of electricity face the full financial burden of CO_2 permits – through e.g. an auction process.

- In our analysis we apply the current SDE policy for the lifetime of the investment. The SDE compensates the operator of renewable energy to the level where costs – including a return – can be recovered.

Based on our assumptions we find a Net Present Value (NPV) for gas-fired power stations around zero, slightly below zero for wind, and a negative NPV for coal-fired power stations, mainly driven by the assumption that the full carbon cost is borne by the producer

- A negative NPV means that the return on the investment is lower than the required rate of return (Weighted Average Cost of Capital – WACC).

- The main reasons for the negative economic outcome for the coal-fired option are:

  - Higher CO_2 emissions from coal-fired power production result in a larger cost for acquiring CO_2 emission permits; and

  - One-off investment costs and structural operating and maintenance costs are higher than for the gas-fired option.

- However, if we assume that CO_2 permits continue to be allocated at no cost to the producer, but are included in the electricity price, the coal-fired power station is economically the preferred investment option.

- In our analysis the coal-fired option requires at least six years of free permits to beat the natural gas option over the whole lifetime of the asset.

- As part of our analysis we have undertaken a detailed sensitivity analysis. We have analysed the impact of 10% increases and decreases in the quantitative assumptions with regard to the electricity prices, the fuel prices, the costs of CO_2, the investment and operating & maintenance costs, and the efficiency. The NPV appears to be most sensitive to changes in (i) the electricity prices, (ii) fuel prices, and (iii) the costs of CO_2 permits.

- Simultaneous increases and decreases of parameters can change the results. However, the sensitivity analysis does not show an overall change in the economic ranking of the three generation options.

- We have undertaken a high level analysis of the potential impact of co-firing with more environmentally-friendly biomass (or biogas) and applying Carbon Capture and Storage (“CCS”) technology. Both the coal and gas generation options can profit from adding biomass or biogas fuels. In the case of CCS our high level analysis confirms the recent findings of the European Commission that under current CO_2 prices CCS is not yet economically nor technically viable.

Investors may have non-economic arguments for investing in particular fuel options

- There may be other arguments for choosing an alternative investment option. Reasons for investing in a coal-fired investment option could be driven by the desire to reduce (supply) risk by diversifying the generation portfolio.

- We have analysed the economic cost of the choice for coal-fired generation. The financial difference can be interpreted as the shadow price of fuel diversification. This shadow price for 1 MW of coal is € 257k for the whole time horizon of our analysis (2030).

- We have also analysed the shadow price for wind, compared to gas. However, wind has a lower load factor than gas or coal. In other words, 1 MW of wind produces less electricity than the equivalent of either gas or coal. In order to make wind comparable to gas the NPV has been adjusted for this lower load factor. This leads to a shadow price of € 134k for wind.

- Both shadow prices, for coal as well as for wind, have been determined from the point of view from the investor.

Executive Summary (3/3)

Overall summary

- Overall we conclude that making decisions with regard to the investment in new electricity production requires extensive and thorough analysis. The "view of the future" of the investor shapes this analysis, which is furthermore dominated by uncertainties and risks. We also find that the role of government policies on sustainability, and the views from investors on future policies, is crucial to the analysis. Based on our assumptions that government subsidies on wind remain stable, CO_2 continues to have a positive price and CO_2 costs are fully borne by the producers, we find that gas and wind are the economically favourable options for investments in generating capacity. However, our analysis also shows that changes in this respect, as well as views on for example fuel diversification strategies, might affect the outcome.

Table 1.1: Main results

	Coal	**Gas**	**Wind**
NPV 1MW	- € 250 k	€ 7 k	- € 37 k
Impact of governmental regulation on the NPV:			
CO_2 permits at no cost	€ 1,315 k	€ 737 k	n/a
No renewable subsidy for wind	n/a	n/a	- € 590 k
CO_2 emissions per annum	5,6 k tonne	2,6 k tonne	n/a

Source: PwC analysis

Section 2

Introduction and background

Introduction and background

- Greenpeace recently published “Energy revolution: A sustainable world energy outlook”. The report develops a global sustainable energy pathway up to 2050.

- The study envisages a transition from fossil-based generation to sustainable-based generation. This study demonstrates that substantial CO_2 reductions are possible through a combination of energy efficiency and sustainable technologies.

- An important contributor to the sustainable transition is the energy sector – in particular the generation of electricity. The electricity sector itself is in transition, because many facilities are due to be retired and need to be replaced.

- As investments in power stations are capital-intensive, the impact of certain fuel types will have a long-term impact on power supply and thus the environment.

- Greenpeace has indicated that it is interested to gain more financial-economic insight into the business fundamentals that drive these investment decisions.

- Sitchting Greenpeace Nederland (“Greenpeace”) has engaged PricewaterhouseCoopers Advisory N.V. (“PwC”) to analyse the economic potential of three different electricity production options in the Dutch energy market: (i) coal-fired, (ii) gas-fired, and (iii) wind-powered.

- For this analysis we have developed a view of the future.

- In order to get an independent projection of the Dutch electricity market, PwC engaged IPA Energy + Water Consulting Ltd. (“IPA”). Based on their propriety model “ECLIPSE” three IPA scenario’s were developed, in addition to one scenario defined by Greenpeace.

- The price projections generated by IPA’s model were subsequently used by PwC to calculate the net present value (“NPV”) of the three different generation options on a marginal basis. This marginal analysis was then compared to an integral approach (this approach is described in more detail in the following section).

- The analysis and conclusions we present in this report are purely based on economic principles. PwC does not make a value judgement between the different investment options and does not imply one option should be preferred above another.

- The ultimate investment decision can take into account a range of other – equally important – considerations, or could include additional not publicly-available information, that could therefore lead to an investment decision that does not necessarily coincide with the analysis we present. The investment decision is thus largely based on a view of the future, which can differ between parties.

Section 3
Our approach

Our approach contains a number of interlinking steps…

2 Projection Dutch electricity market

- Prices
- Load factors
- New investments
- Import/export
- …….
- …….

IPA

4 Marginal analysis

- Financial analysis of investing in 1MW of generation option
- Analysis of differences
- Sensitivity analysis

5 Integral investment assessment

Qualitative assessment of factors, such as...

...fuel diversification and security of supply
...portfolio approach
...scale effects

1 Scenario definition

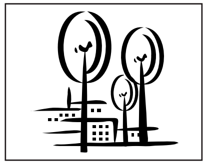
IPA	Greenpeace
Low Case	Greenpeace
Base Case	
High Case	

IPA

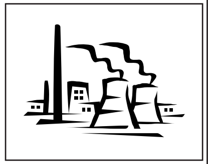
3 Definition investment options

Gas-fired

Wind



Coal-fired



Overall conclusions and implications

…that ultimately lead to the financial economic analysis of production alternatives

- Our approach contains a number of steps that are presented schematically on the previous slide.

1 Scenario definition

- In the first step of our approach a number of different scenario's are developed about the underlying drivers of electricity prices. These include, inter alia, assumptions about future electricity demand, import and export possibilities, fuel prices, subsidy levels, and CO_2 prices.

- In the case of wind we take the recently announced Dutch renewable subsidy framework into account.

- Three likely scenario's have been developed by IPA and one future scenario has been developed by Greenpeace – based on their assumptions of the underlying drivers of electricity prices.

- These scenario's are used in the next step of the analysis.

2 Projection Dutch electricity market

- The four pre-defined scenario's are used in Step 2 to generate projections for the Dutch electricity market using IPA's ECLIPSE (see Section 4).

- There is a substantial amount of data generated by ECLIPSE and includes, inter alia, electricity prices, load factors, new build, retirements, emission levels, and production statistics.

3 Definition investment options

- In step 3 three standard ("plain vanilla") investment options for coal-fired, gas-fired, and wind generation are defined. We rely on the basic plant characteristics and statistics used by IPA combined with public data for each investment option. This means we rely on proven and existing technology.

4 Marginal analysis

- In Step 4 we analyse the economic case of building 1MW. By analysing 1MW we can compare the three investment options on a like-for-like basis and we can assume that this marginal investment will not influence prices or competitor behaviour in the market. This step includes an analysis of the profit drivers and the sensitivity of the results to changes in assumptions.

5 Integral investment assessment

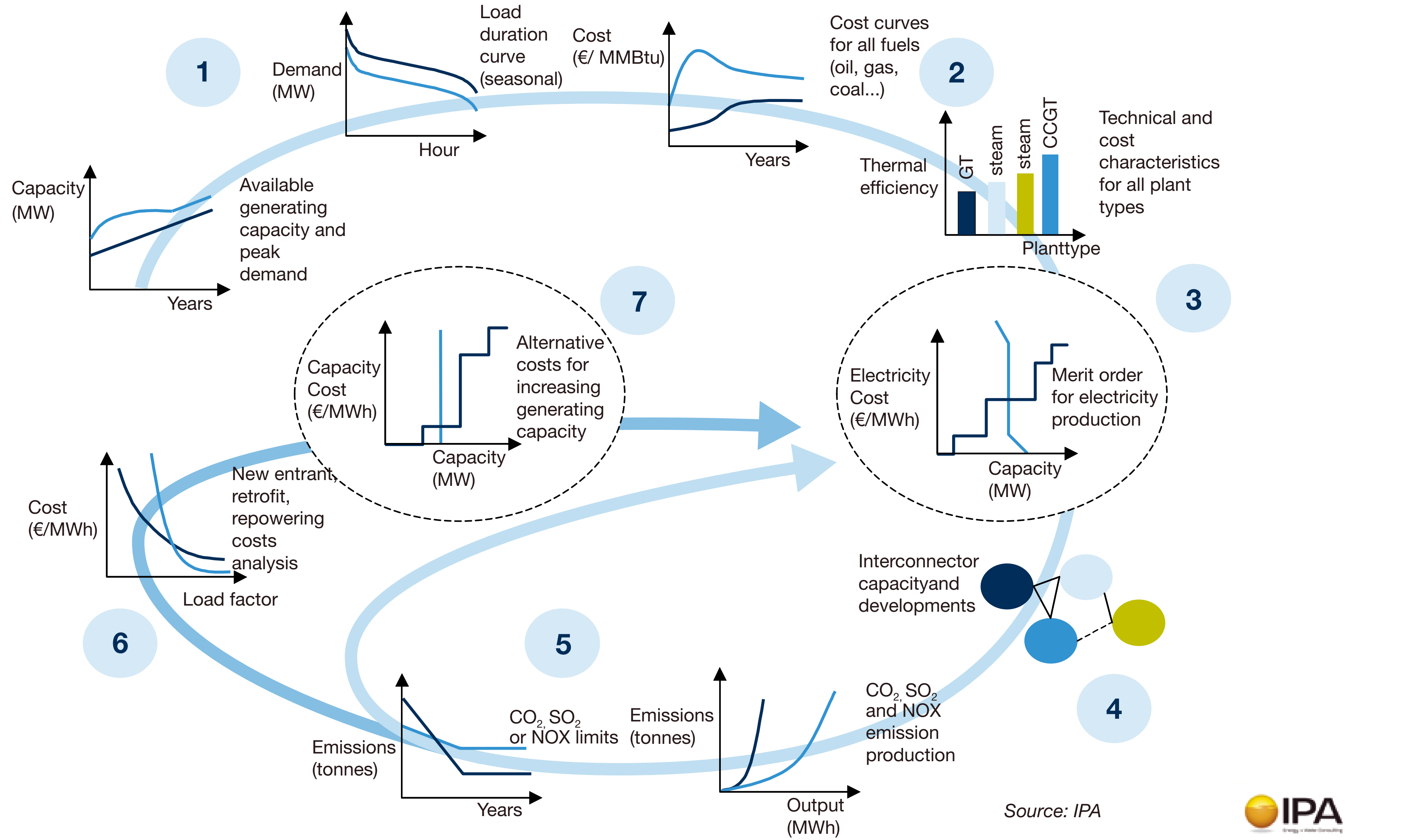
- In Step 5 we analyse the three production alternatives taking other qualitative factors into account, such as fuel diversification strategies, security of supply, and scale effects of investing beyond the marginal 1MW example.

Section 4

IPA price projections: key assumptions and main findings

IPA's proprietary energy market modelling tool is used to replicate the operation of the actual Dutch power market (1/3)

Figure 4.1: IPA ECLIPSE



Source: IPA

IPA's proprietary energy market modelling tool is used to replicate the operation of the actual Dutch power market (2/3)

- IPA has developed a modelling tool that is designed to replicate the operations of an actual power system (ECLIPSE).
- ECLIPSE includes an accurate engineering representation of all of the physical assets needed to create a power system, i.e., every power plant, every transmission link, every fuel supply option available to the power system.
- By including the economic and environmental constraints facing system operators in the real world, ECLIPSE replicates how actual decisions are made by power system operators when subject to any slate of constraints, such as physical, economic, or environmental constraints.
- Conceptually it is simpler to think of the model carrying out a series of discrete tasks, this is graphically depicted on the previous slide (for a full discussion of ECLIPSE we refer to the accompanying report by IPA). The main steps are:

1 Current capacity and demand

- Detailed information of existing generating capacity and the characteristics of demand is required. The demand for electricity can be subdivided into two key components: hourly demand and total annual demand. The hourly demand, or load profile, is the demand for electrical energy on an hour-by-hour basis across the whole year.
- In addition to this demand being met, an adequate safety margin needs to be maintained in the form of non-generating capacity in case of any sudden failure in generating capacity. This capacity reserve margin is usually measured as a percentage of the highest demand in the year (peak demand).

2 Generation-specific operational costs

- When determining how to generate electricity to meet a certain level of demand at minimum cost, available power stations need to be ranked according to their generation-specific operating costs.
- These include capital, fuel and operating and maintenance costs, where information is needed for fuel options and prices, as well as detailed information on the technical characteristics of existing power stations.
- The fuel cost takes into account the fuel price and the technology-specific fuel-to-electricity conversion factor (thermal efficiency).

3 Initial dispatch to meet demand

- Once the costs per unit have been defined, the model dispatches as many resources as required. Not withstanding other constraints as detailed below, the lowest cost resources are dispatched first.

4 Network constraints

- Network constraints can influence the initial dispatch in Step 3. Electricity travels from power stations to consumers via high and low voltage transmission and distribution networks.
- Due to constraints and bottlenecks in this network, the most cost-effective solution to meeting a certain electrical load may in fact not be technically feasible. Despite the robustness incorporated into a lot of electrical equipment, there are a number of events that must be avoided.
- In order to limit the possibility of damaging sensitive equipment, more expensive electricity from a power station that has an unhindered access to consumers may be requested instead of cheaper power at the wrong side of a bottleneck.

5 Emission constraints

- The relative cost of production of different power stations can also be affected by the application of environmental constraints.
- If a power station has to pay for emissions of CO_2 by having to purchase emission allowances, this additional cost must be added to the cost of production estimate.

IPA's proprietary energy market modelling tool is used to replicate the operation of the actual Dutch power market (3/3)

- ECLIPSE takes these types of constraints into account whether these are defined in terms of allowance prices (measured in € per tonne of pollutant emitted) or emission limits (measured as weight limits or rate caps).

6 Entry and exit constraints

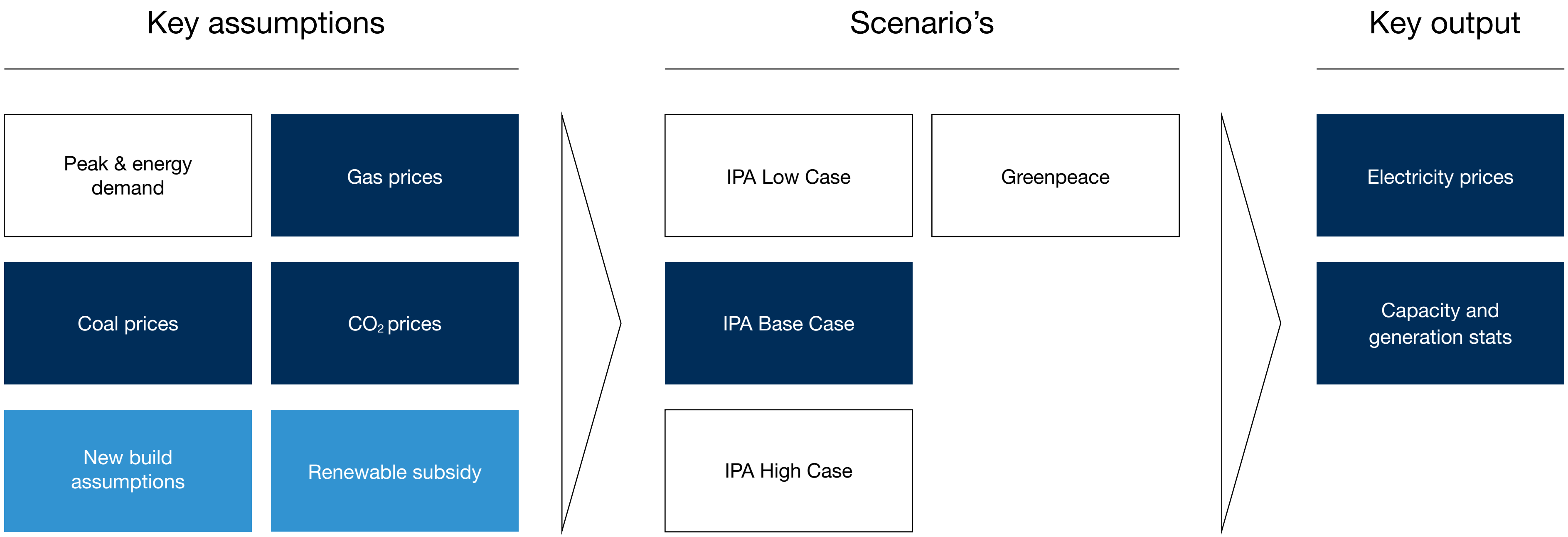
- In order to meet a certain demand and maintain adequate safety standards new power stations can be built (or existing stations closed) or retro-fitted.

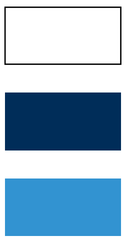
- These possibilities introduce a further constraint (option) for the optimal least-cost dispatch to meet demand.

7 Alternative costs for meeting demand

- Given the constraints in Steps 4, 5, and 6 an alternative cost pattern is calculated for meeting demand. This information feeds back into Step 3 where another dispatch is undertaken to meet demand at a total least cost.

Key assumptions, scenario's and key output from IPA's ECLIPSE





Available in the appendices to this report and the IPA report.

Discussed in this section.

Discussed in marginal analysis.

IPA Base Case scenario: key assumptions (1/3)

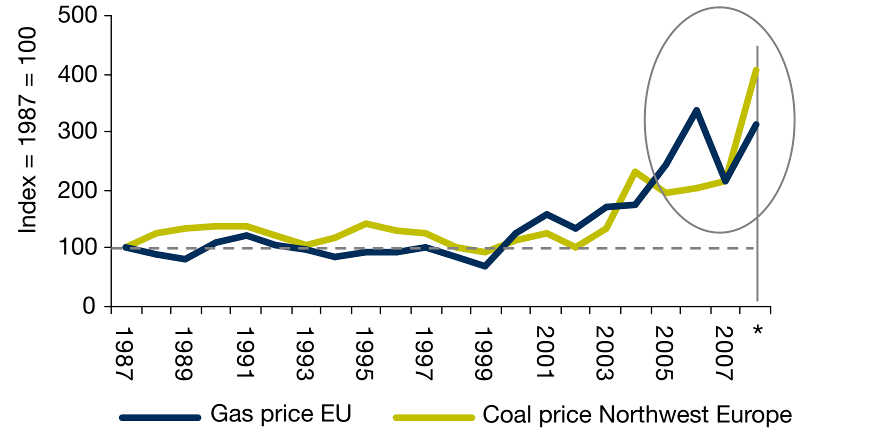
The price of carbon – who pays?

- IPA has assumed that there will be a positive price for carbon. This assumption seems plausible given the European Commission's sustainability targets and the continued attention to CO_2 reductions.
- A trading scheme based on weight targets, rather than a price approach with e.g. a carbon tax, looks likely to remain the government's favoured method for achieving carbon emission reductions (given also the success of the Emission Trading Scheme ETS).
- In ECLIPSE the cost of CO_2 emissions is included when projecting the electricity price by assuming that generators incorporate the full cost of CO_2 permits in the electricity price.
- This implies that the full opportunity cost of carbon is included in the price projection. In our marginal analysis, discussed later, we calculate the economic consequences when the full cost of carbon is both included and excluded from the cost base of a producer.
- This addresses the issue whether permits are given away for free, in which case the carbon cost is zero for generators, or whether permits have to be purchased, in which case the cost is positive for generators. In both cases the value of the permits is included in the electricity price.

Gas versus coal prices – the past

- Gas prices have risen sharply since 1999 following the upward development of oil prices.
- The development of gas prices relative to coal prices diverged between 2005 and 2006, where the gas price increased substantially more than the coal price. However, coal prices have recently also increased sharply.
- In the IPA projections this gap is expected to close over time, aligning the price development of coal and gas (see next slides).

Figure 4.2: Historic gas and coal prices (1987 = 100)



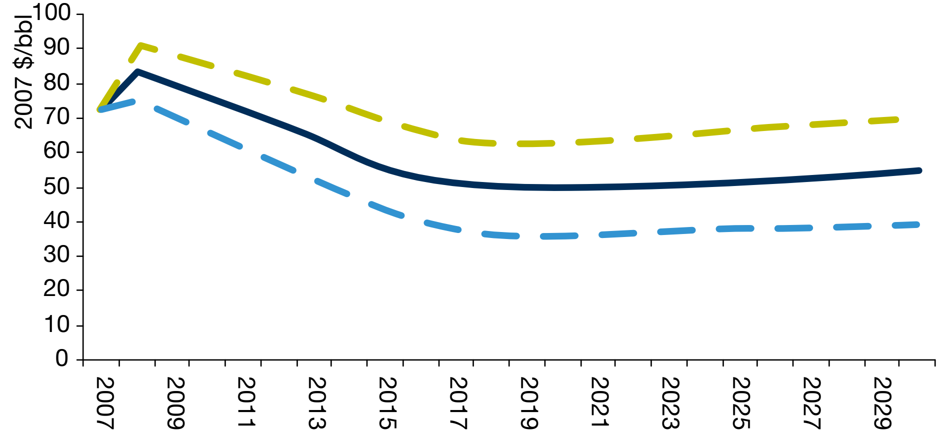
Source: BP Statistical Review 2007, APX, EEX, PwC analysis.
**Prices for 2008 as per March 2008.*

IPA Base Case scenario: key assumptions (2/3)

Oil price projection

- The oil price is expected to remain high in real terms. According to IPA new production sources after 2010 may release some of the pressure on the price.
- Prices stabilise between USD40/bbl and USD70/bbl range by 2020 in the Low and High Case respectively.
- Prices rise after 2025, according to IPA this is due to potential supply constraints.
- Current March prices, based on Bloomberg, are in excess of USD105.*

Figure 4.3: Oil price projection

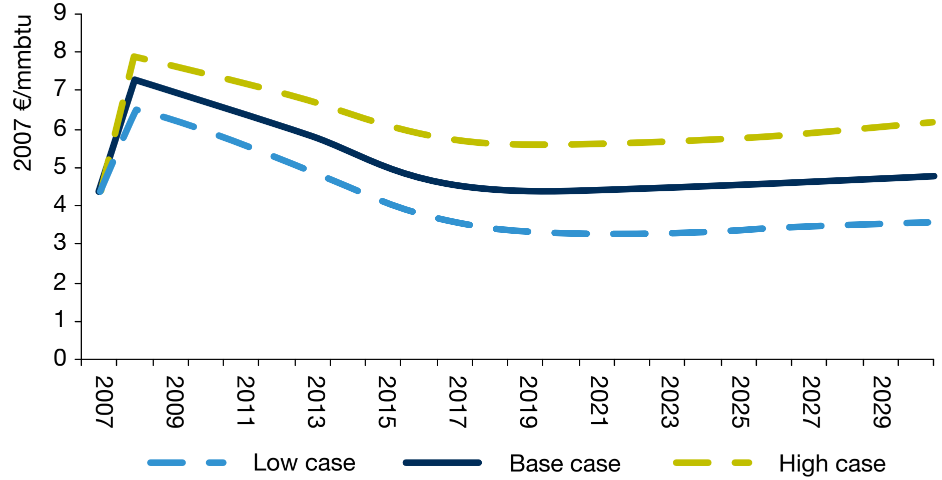


Source: IPA

Gas price projection

- Gas prices follow oil prices to some extent with prices stabilising between the € 3/MMBTu and € 6/MMBTu by 2020.
- Current March market prices, based on EEX, are € 6.8/MMBTu.*

Figure 4.4: Gas price projection



Source: IPA

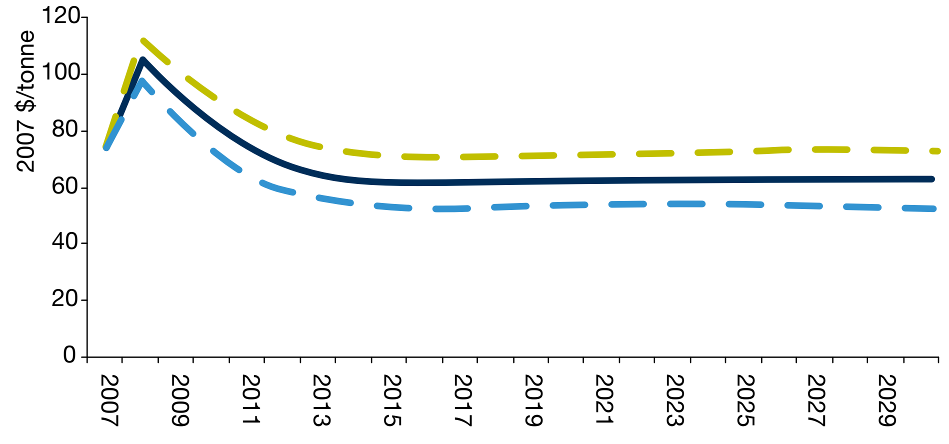
* *Current prices are nominal.*

IPA Base Case scenario: key assumptions (3/3)

Coal price projection

- The coal price is projected by IPA to spike in the medium run due to high demand and supply constraints.
- After 2009 prices are assumed to stabilise to the level between USD50 /tonne in the Low Case and USD70/tonne in the High Case by 2015.
- Current March prices, based on EEX, are at USD145.*

Figure 4.5: Coal price projection

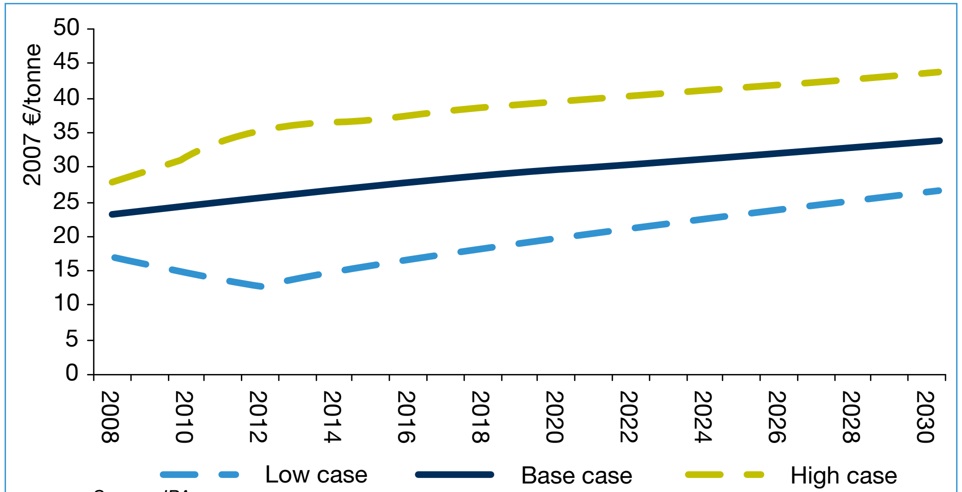


Source: IPA

Carbon price projection

- Carbon prices are projected by IPA to increase steadily in both High and Base Cases.
- The Low Case explores the possibility that the market for carbon permits will not be very tight in 2008-2012. Prices only firm up after this.
- The current price benchmark for contracts with a settlement date in December 2008 is at € 21.26 per tonne; December 2009 is at € 21.79; December 2011 at € 23.55 (source: ECX).*

Figure 4.6.: CO_2 price projection



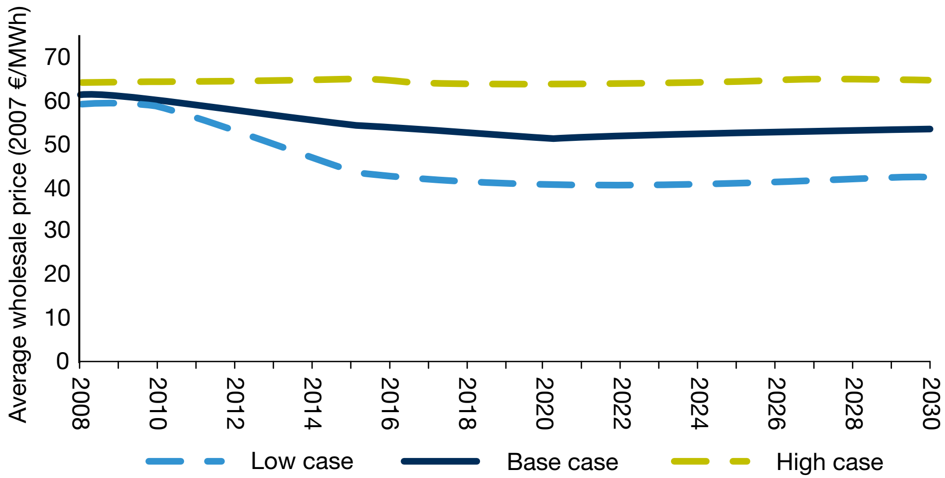
Source: IPA

* *Current prices are nominal.*

IPA Base Case: electricity price projection

- The IPA projected electricity prices generally follow the commodity price trends downwards.
- Prices also fall due to new capacity coming online in the Netherlands, Germany and France.
- The new capacity reduces the average cost of production over time thereby supporting the reduction in electricity prices.
- In the Low Case, lower commodity prices have a noticeable impact on electricity prices, whilst in the High Case, higher carbon prices offset the effect of decreasing gas and coal prices on power prices.
- Prices stabilise in the 40-62 €/MWh range in 2020 and then rise slightly in the 2020-2030 period.
- Current March base load power prices, based on Endex, are around 65 €/MWh.*

Figure 4.7: Projection of electricity prices in the Netherlands



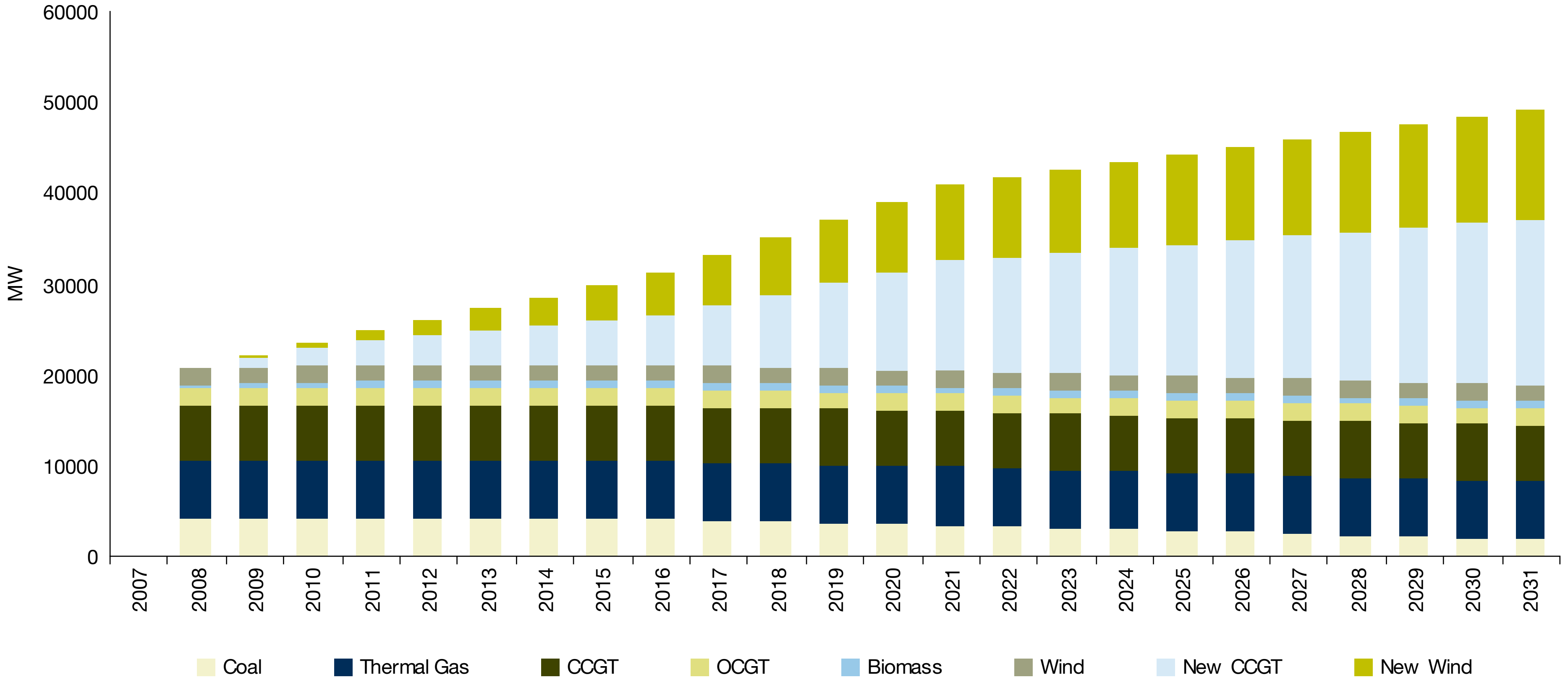
Source: IPA

* *Current prices are nominal.*

IPA Base Case: new build projection

- In the Base Case gas-fired generation is the least cost option to meet increases in demand.
- Wind plant development has been synchronized with the government targets for renewable energy. This means the amount of wind energy is not an **output** but an **input** in ECLIPSE.

*Figure 4.8: Capacity development in the Netherlands**



Source: IPA

* *Diesel, Hydro, HFO, Nuclear and new OCGT are not included in this picture.*

Section 5

Three production alternatives

Three production alternatives are analysed

	Gas-fired	Wind	Coal-fired
Technology	Combined Cycle Gas Turbine (CCGT). H system technology considered "state-of-the-art". The H System integrates gas and steam turbine, re-pressure heat recovery steam generator (HRSG) and a liquid-cooled generator into one unit.	We assume an average wind turbine capacity of 3MW installed in a medium-sized wind park of 10-15 MW.	Pulverised Fuel (Advanced Super Critical) with Flue Gas Desulphurisation (PF ASC). This is considered the base case coal technology, which is being deployed around the world.
Investment costs	672 €/kW, depreciation 15 years	1,250 €/kW, depreciation 15 years	1,285 €/kW, depreciation 30 years
Fixed O&M costs	26.1 €/kW	24.0 €/kW	39.3 €/kW
Variable O&M costs	0.6 €/MWh	10.0 €/MWh	3.5 €/MWh
Carbon emissions	352 kg/MWh	0 kg/MWh	752 kg/MWh
Efficiency	58%*	n/a	45%*
Load factor	85.5%	25%	85.5%

* *Lower Heating Value*

Sources: IPA, DTI, ECN, NEA; Note: all costs are in 2007 Euros.

Section 6

Marginal financial analysis

By analysing 1MW we can compare the three production options on a like-for-like basis

Marginal analysis: What are the effects of 1MW of extra capacity?

- We have analysed the effects of adding just 1MW of extra production capacity in the Netherlands. This allows us to study the effects of comparable sizes without having to take other effects into account (the ceteris paribus assumption). With this ceteris paribus assumption we can assume that our 1MW plant does not have any influence on prices, behaviour, or investment decisions of competitors. We discuss the potential impact of scaling up the size of the investment in Section 8.

- We have carried out financial analyses for three investment “plain vanilla” options, i.e. standard coal, natural gas and wind onshore. These options have been proposed by Greenpeace. In Section 9 we discuss variations on the these plain vanilla options, e.g. wind offshore, the use of biomass (biogas), the combination of electricity production with heat off-take, and Carbon Capture and Storage technology.

Cash flow statements for the generation possibilities

- We generate cash flows for the investment options running until 2030 – the last year for which price and fuel cost projections are available from IPA. These cash flows are subsequently discounted to generate an NPV of the investment option per 2007. The NPV per investment option can subsequently be compared.

- In the case of wind, our analysis runs for the lifetime of the investment to coincide with the renewable subsidy.

Net Present Value comparison

- The NPV of an investment is a criterion for deciding whether or not to undertake an investment.

- NPV answers the question of how much cash an investor would need to have today as a substitute for making the investment. If the NPV is positive, the investment is worth taking on because doing so is essentially the same as receiving a cash payment equal to the NPV.

- If the NPV is negative, taking on the investment today is equivalent to giving up some cash today, and the investment should be rejected from a financial point of view.

Key assumptions for our analysis

- On the next sheets we set out the main assumptions underlying our financial analysis.

Key assumptions for the marginal analysis (1/2)

Discount rate: Cost of Capital

- For the discounting of the cash flows we use the same cost of capital (WACC) for all three investment options. This assumption does not take into account the possibility that the risk profile of the different investment options can differ.
- It is beyond the scope of this study to calculate three separate discount rates for the three investment alternatives. In Appendix C, we analyse the impact of varying the discount rate on the NPV outcomes.

Capital costs are annualised

- The different power plants have different depreciation schedules. It would be unfair to compare the NPV of these projects without taking this into account. We have therefore annualised the capital costs of gas and coal using an annuity method. We assume that after the plant is depreciated a new one is built with exactly the same real costs as in 2007.
- The SDE subsidy is granted for 15 years. Therefore, we undertake the analysis for wind over the lifetime of the investment (15 years). Extending or renewing the investment would require extra assumptions, such as the availability of a new equivalent subsidy and the characteristics of new wind turbines in the future (investments, O&M costs, etc). For gas and coal the time horizon of our analysis is 2030.

Timing of the investment

- We assume the investment option becomes online immediately and generates income from day one. We therefore do not take planning, permitting, and commissioning issues into account.

Location costs

- For all three investment options the location of the plant is of crucial importance.
- For a coal plant it is a big advantage to be located near a port. The coal can thus be transported more cheaply. For cooling purposes sea water can be used.
- For the gas-fired power station a location close to suitable gas infrastructure is essential.
- For wind parks location is even more important. A small percentage more wind in a year has a significant impact on the financial profitability of a project.
- For the purposes of our study we assume that all three investment options will be built in ideal and suitable low cost areas, such as close proximity to a port, gas infrastructure and windy areas.

Fuel availability and grid connection

- We assume that there is free access to all three fuels without supply constraints.
- After a plant is built it has to be connected to the electricity grid. These costs are particularly large for wind parks because every wind turbine is usually connected separately. The specific connection costs per investment are included in our initial investment costs.

Wind specific costs

- We apply the recently announced subsidy for renewable power*. This system sets the subsidy so that the NPV outcome is zero. That is to say, all costs can be recovered – including a return – by an investor.
- Wind generation is exposed to large fluctuations in production. We have accounted for imbalance costs. These are estimated at 11% of the electricity price.

* *Source: Staatscourant, "Algemene uitvoeringsregeling SDE", 3 March 2008*

Key assumptions for the marginal analysis (2/2)

CO_2 emissions

- In our analysis we assume that producers face the full cost of carbon emissions.
- We have used the emission factors for coal and gas based on data from the Dutch Emission Authority (NEA).*

Load factor

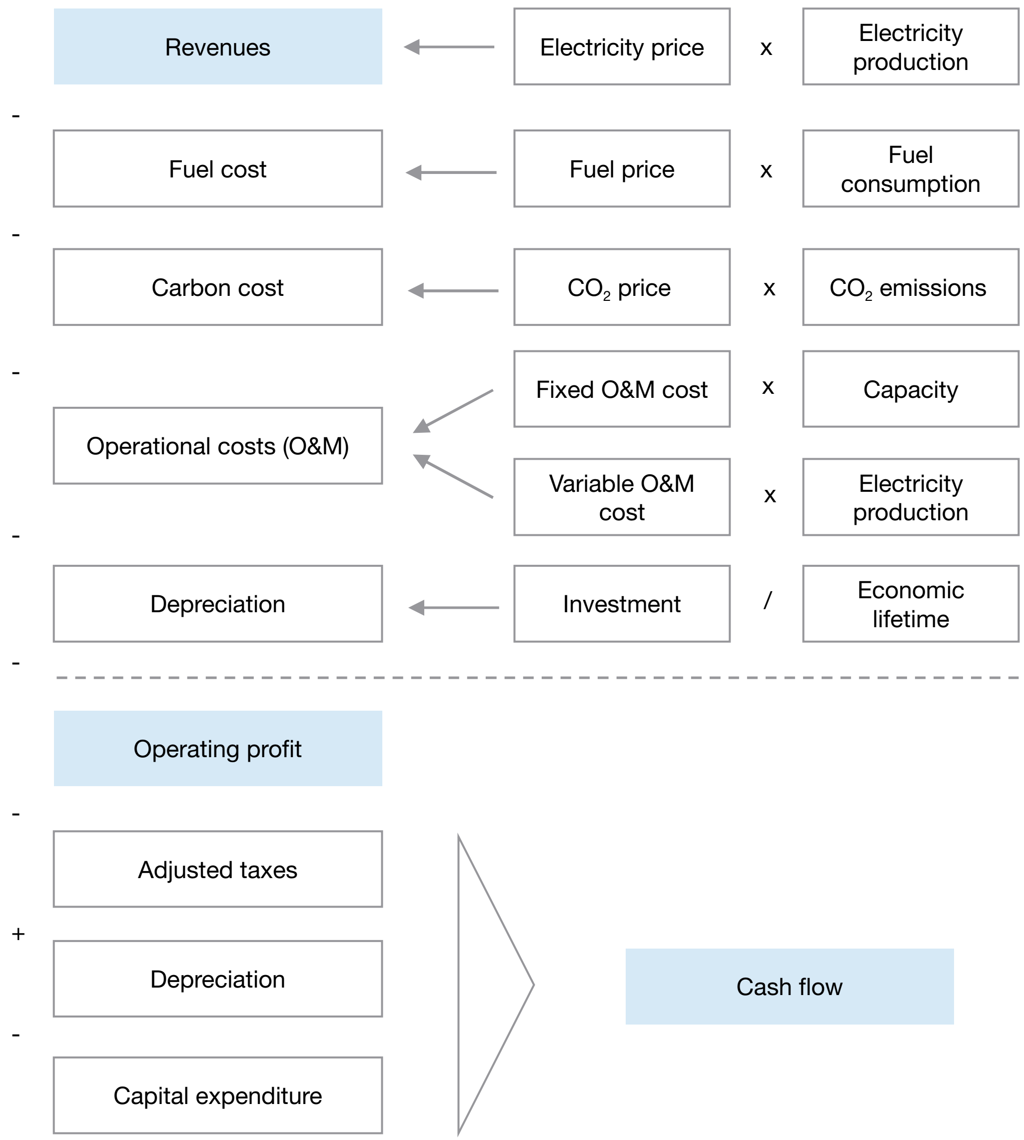
- We assume that the 1MW investment will be utilised at full potential capacity – according to the technical specifications (see Section 5).

Base load versus peak power prices

- The IPA model generates an integrated electricity price and does not distinguish between base load power prices and prices in peak moments. A particular generation option may be able to profit from providing additional power in moments of greater demand and benefiting from greater flexibility. We do not take this potential upside into account.

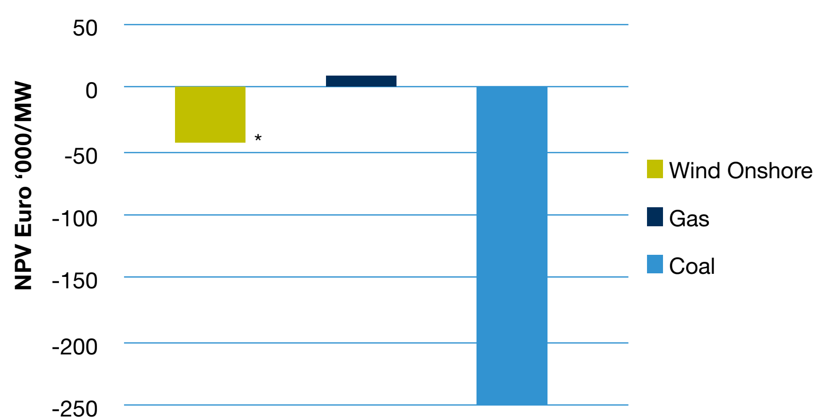
** Source: NEA (2007), "Leidraad CO_2 -monitoring"*

We project expected cash flows for each production option until 2030



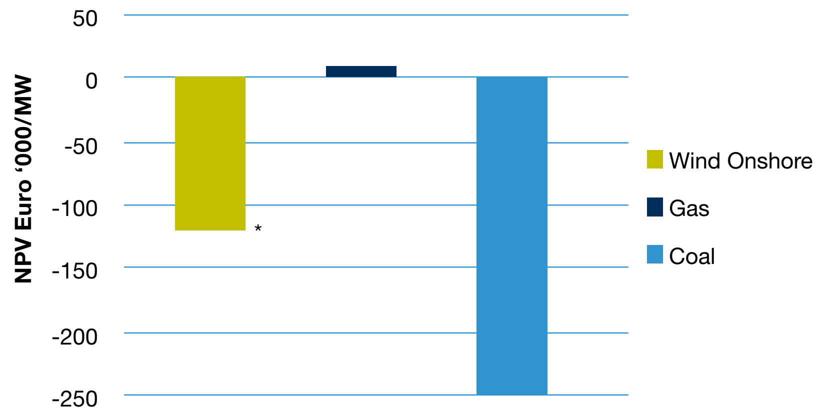
NPV results for three production alternatives: coal has a negative NPV

Figure 6.1: Net present value per MW in the IPA Base Case



Source: PwC analysis
**Wind based on a 15-year NPV.*

Figure 6.2: Net present value per MW in the IPA Base Case, wind corrected for load factor



Source: PwC analysis
**Wind based on a 15-year NPV, corrected for load factor*

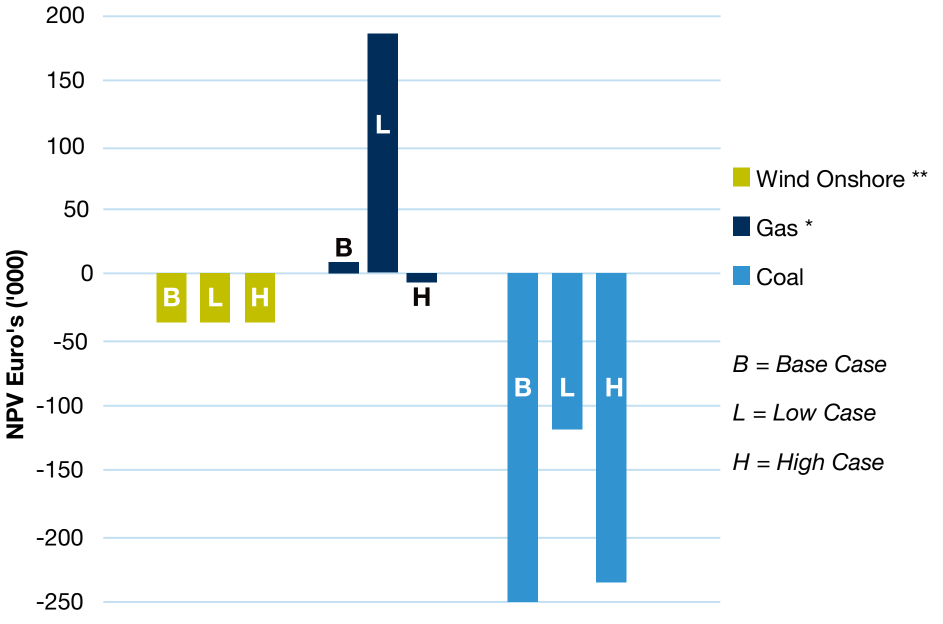
- The NPV outcome for the coal-fired investment option is -€ 250k per MW. This implies that the cash flows that are generated with this investment do not allow a full recovery of the initial investment cost.
- Scaling this figure up to an investment size of 1,000 MW would suggest an NPV of -€ 250 mln.
- The NPV for the gas-fired investment alternative is slightly positive at € 7k per MW. In the ECLIPSE model increases in demand are met by building marginal gas-fired capacity. Therefore, we would expect to find that our gas-fired option has an NPV close to zero.*
- For wind onshore we find a NPV of -€ 37k per MW. We have taken into account the new Dutch subsidy system. In this system the subsidy is set so that an NPV=0 is achieved over the lifetime.*
- The load factor for wind is lower than for gas and coal (25% compared to 85%). In order to make the NPV comparable on a production basis, the NPV of wind needs to be multiplied by 3.4 (i.e. 85%/25%). Figure 6.2 shows this load factor corrected NPV.

* *The reason for finding a deviation from NPV=0 is due to timing effects when the capacity becomes available and the fact that we assume full capacity utilisation whereas the ECLIPSE model adjusts utilisation within the overall optimisation of the system.*

** *The reason for finding a deviation from NPV=0 in the case of wind is the difference with the discount rate used for the subsidy.*

NPV results for three energy price scenarios: coal has a negative NPV

Figure 6.3: Net present value per MW in the IPA Base Case, high case and low case



Source: PwC analysis
Wind based on 15-year NPV

- IPA has developed three scenarios for fuel price development and forward curves. Our analysis is mainly based on the Base Case of IPA.
- In the Low case both power and commodity prices are substantially lower than in the Base Case. The gas price decreases relatively more. This results in an NPV increase for both gas and coal, with gas profiting most.
- The power price in the Low Case stays below the SDE subsidy per kWh. Therefore there is no change for wind compared to the Base Case.
- In the High Case power and commodity prices are higher. The net effect of both on the NPV of gas and coal is limited.
- As with the Low Case, the power price stays below the SDE subsidy per kWh. Therefore, for wind there is no change of NPV compared to the Base Case.

* *The reason for finding a deviation from NPV=0 is due to timing effects when the capacity becomes available and the fact that we assume full capacity utilisation whereas the ECLIPSE model adjusts utilisation within the overall optimisation of the system.*

** *The reason for finding a deviation from NPV=0 in the case of wind is the difference with the discount rate used for the subsidy.*

Key financial results all three production alternatives

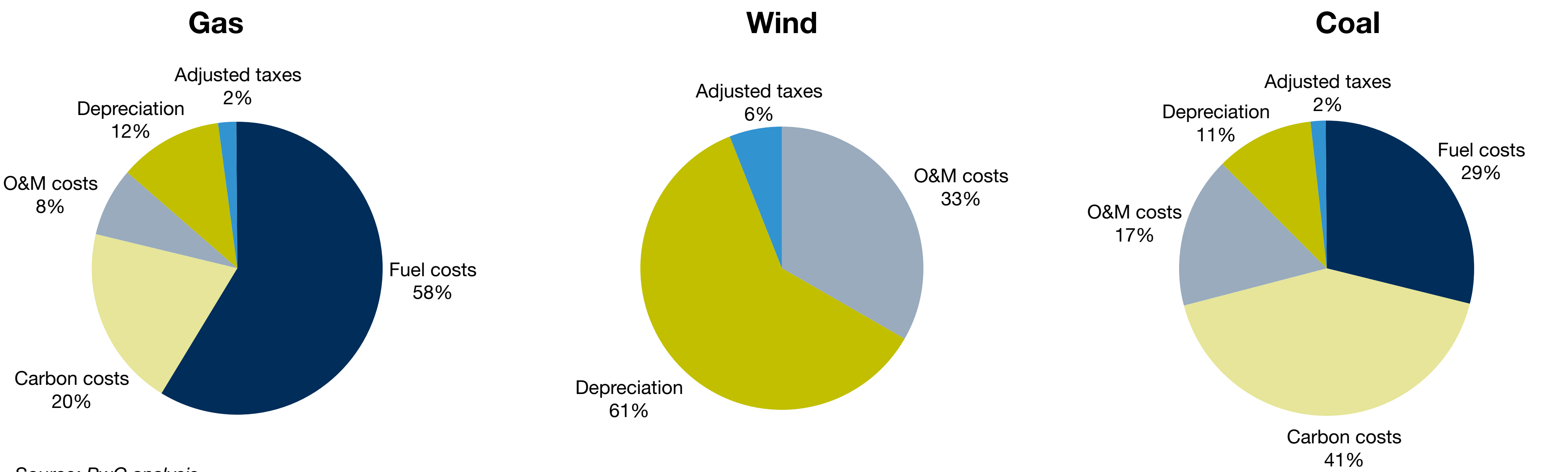
Table 6.1: Key financial results in the IPA Base Case

	Gas-fired	Wind	Coal-fired
NPV (per MW)	€ 7,000 per MW	- € 49,000 per MW	- € 250,000 per MW
NPV (per MW, wind adjusted for load factor)		- € 127,000 per MW	
CO_2 emissions	2,6ktonne	n/a	5,6ktonne
Annual electricity production	7,490MWh	2,200MWh	7,490MWh
Average fuel cost	€ 227	€ 0	€ 113
Average carbon cost	€ 77	€ 0	€ 164
Average operational costs (O&M)	€ 30	€ 46	€ 65
Average depreciation	€ 45	€ 83	€ 43
Average adjusted taxes	€ 8	€ 6	€ 6

Source: PwC analysis

Cost drivers per production option

Figure 6.4: Costs components of investment options in the IPA Base Case



Source: PwC analysis

- Fuel costs dominate the total cost base of a gas-fired power station, with approximately 58% of the costs.
- Carbon costs associated with the emissions of CO_2 are also substantial with approximately a 20% share.

- Wind power does not have fuel costs or CO_2 costs.
- The cost base is dominated by depreciation and O&M costs, with a share of 61% and 33% respectively.

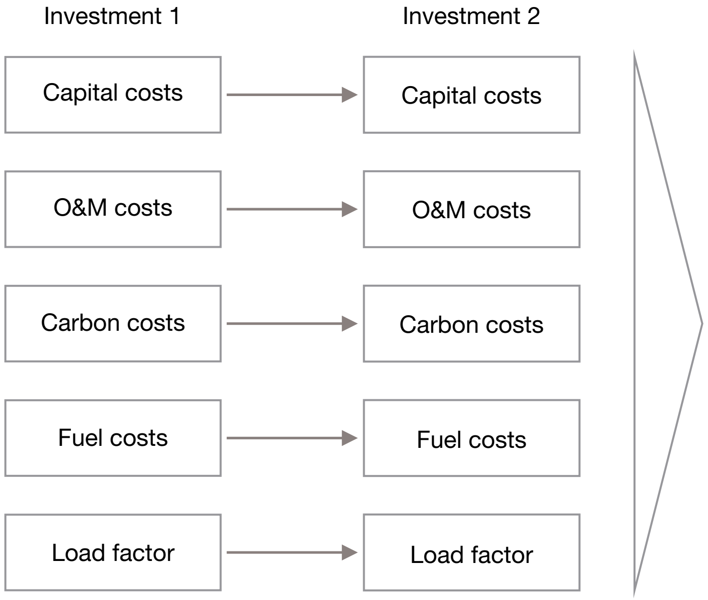
- As opposed to the gas-fired option, the coal-fired power station has relatively lower fuel costs (coal is cheaper than gas). The total share is 29% (for gas this is 58%).
- However, the carbon costs are more substantial, making up 41% of the cost base, compared to 20% for gas-fired power stations.

Section 7

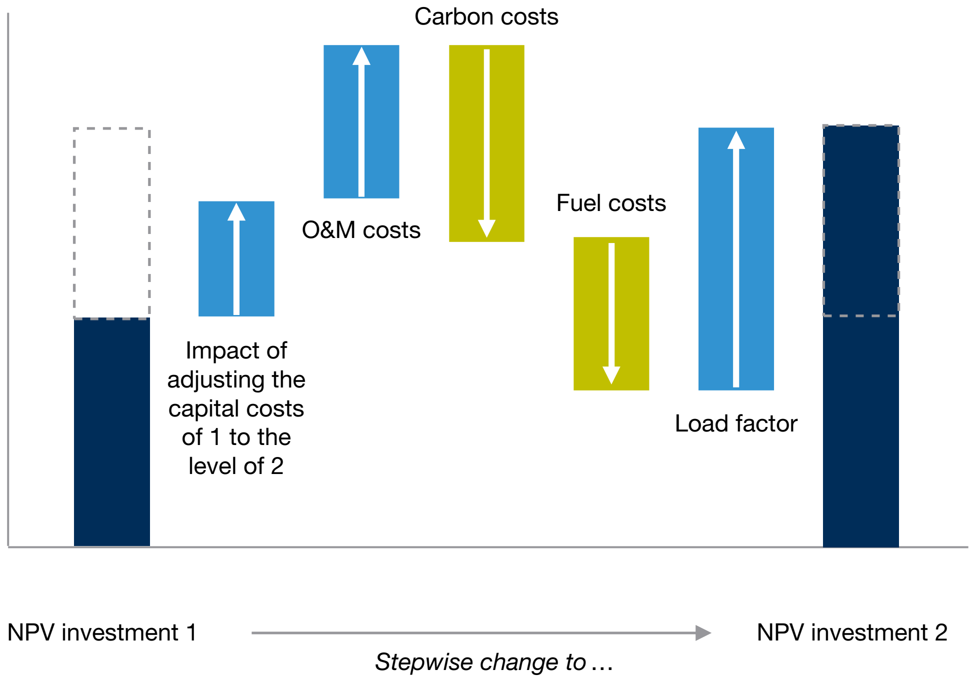
Marginal profit drivers and sensitivity analysis

Fundamental profit drivers: by adjusting each profit driver independently we can identify the key differences between the three options

By adjusting the profit driver from investment option 1 to the level of investment option 2 step-by-step, we can identify the marginal impact on the NPV…



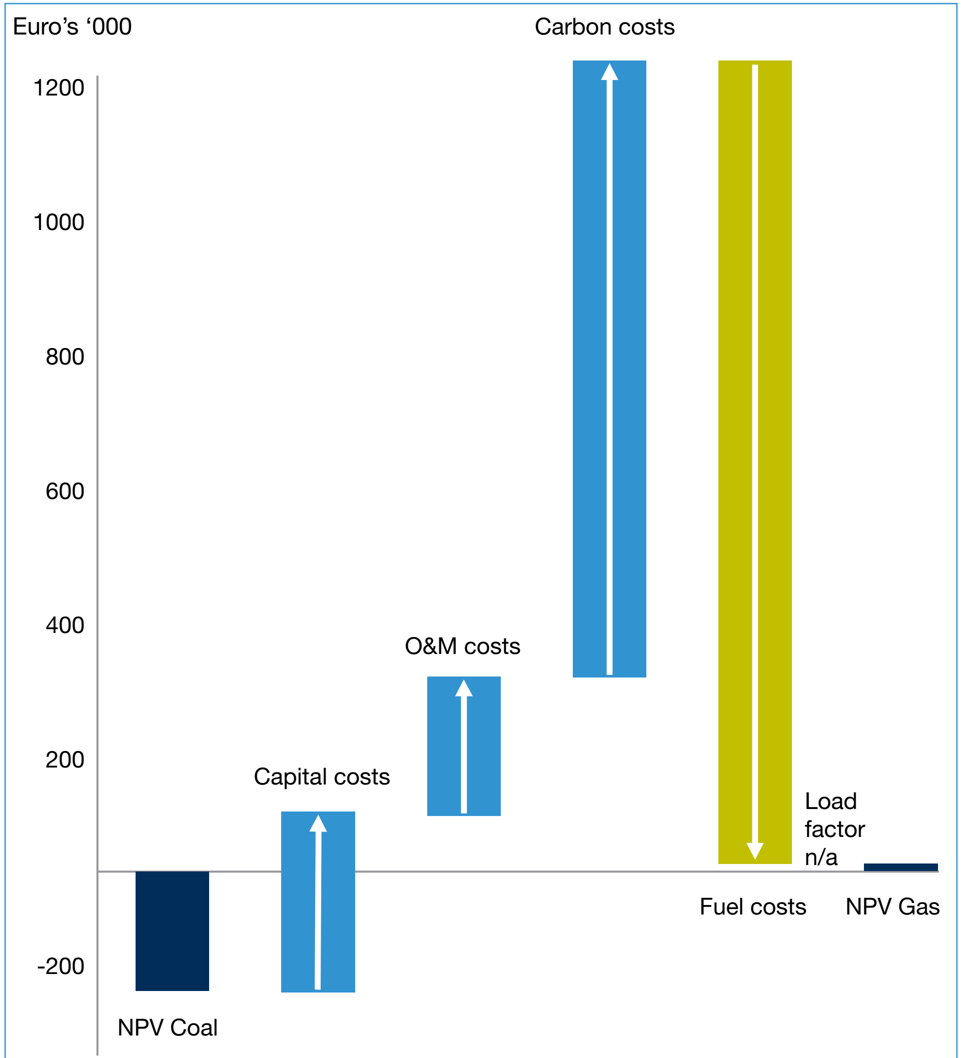
Impact on NPV of adjusting …. from investment option 1 to the level of investment option 2



Profit drivers: comparing coal and gas

- Adjusting the coal-fired power station's capital costs, O&M costs and carbon costs to the same level as the gas-fired power station increases the NPV substantially.
- For these three profit drivers, the gas-fired power station is more competitive than the coal-fired station.
- There is a strong negative adjustment however, when we adjust the fuel costs to the level of the gas-fired station. Coal is substantially cheaper than gas.
- The fuel cost adjustment almost mitigates the NPV increase as a result of lower capital costs, O&M costs and carbon costs.

Figure 7.1: From coal to gas in the IPA Base Case

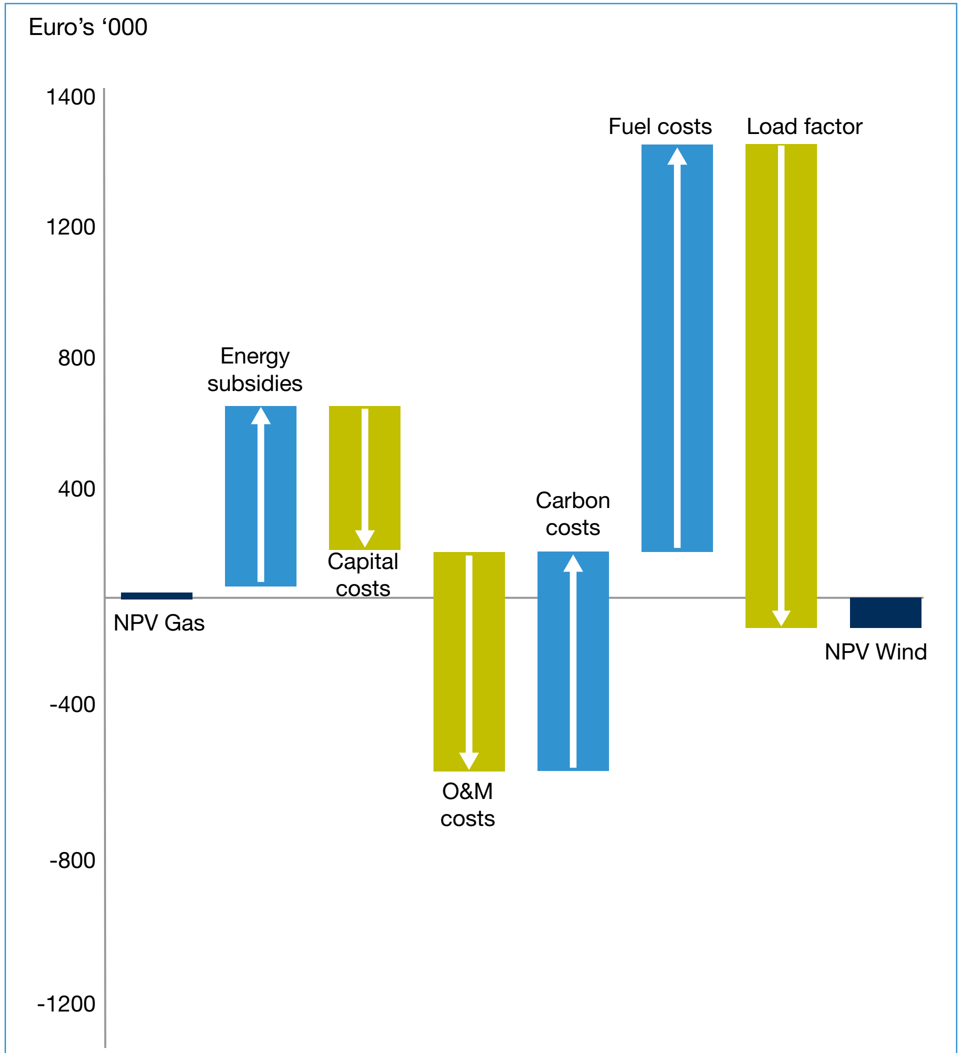


Source: PwC analysis

Profit drivers: comparing gas and wind

- To make a fair comparison between wind and gas we have analysed both options until 2022 (15 years). This is the same as the assumed economic lifetime of both plants.
- Wind has no fuel and carbon costs. These are together with the green energy subsidies relative advantages for wind.
- The capital costs of wind are higher than the costs for a gas-fired plant. O&M costs are higher as well.
- In our model we have assumed a load factor for a gas-fired plant of 85.5%. The availability rate of wind onshore is 25%. This is a large difference, which lowers the NPV of wind substantially.

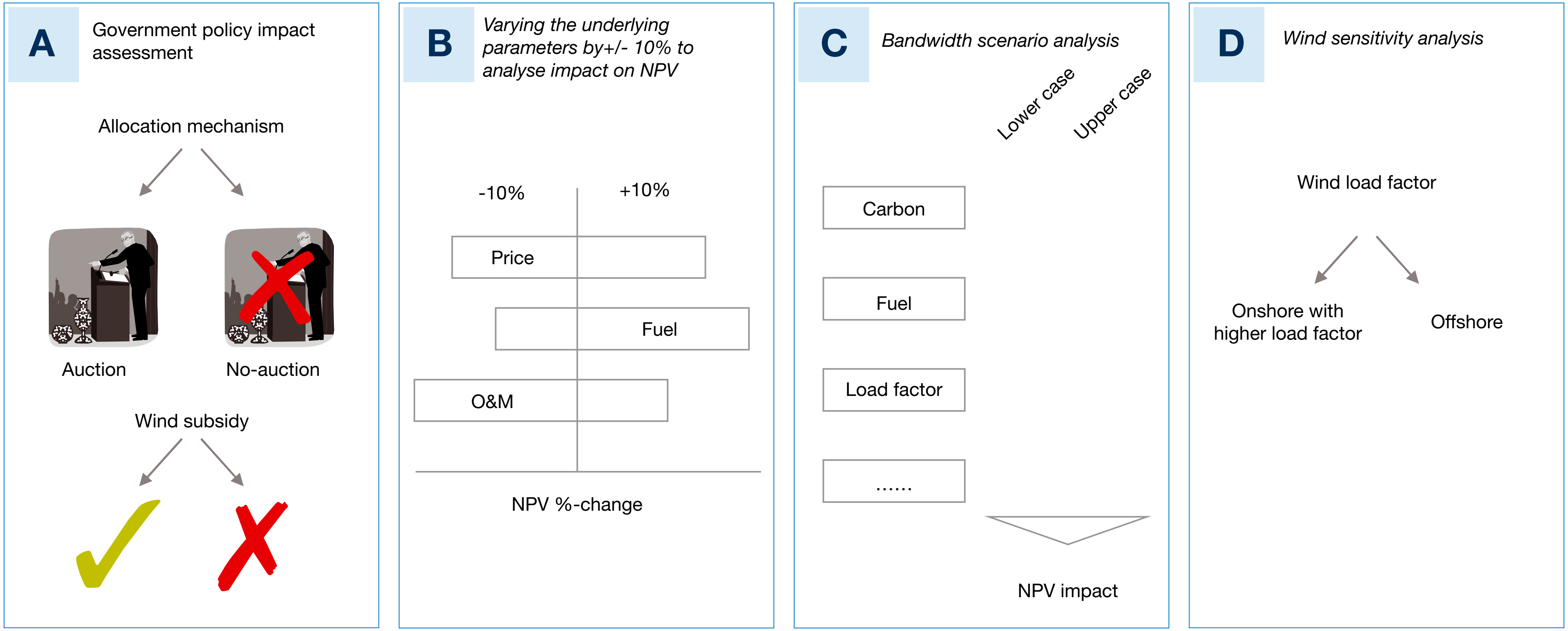
Figure 7.2: From gas to wind in the IPA Base Case



Source: PwC analysis

Sensitivity analysis

We undertake four different types of sensitivity analyses…

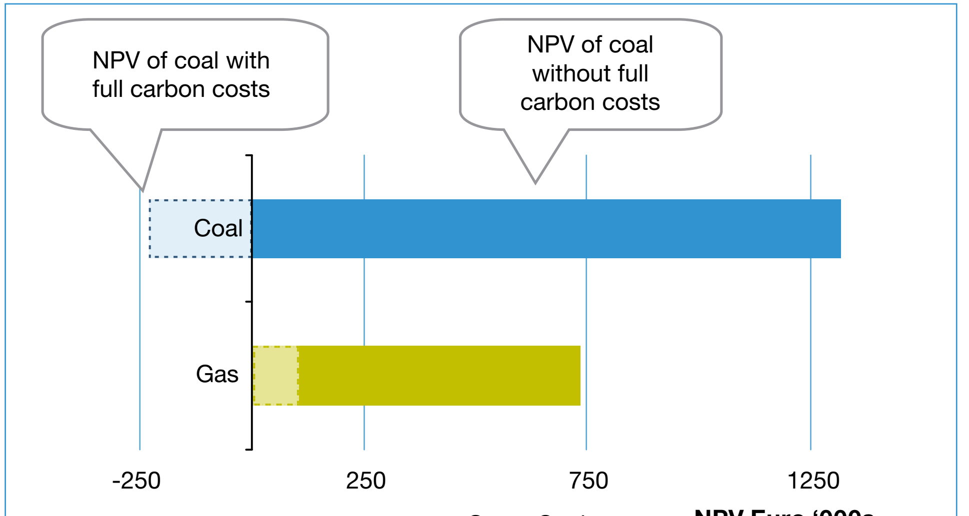


A

If CO_2 permits are not auctioned, coal becomes the relative favourable option

- In the past CO_2 permits were allocated to power generators. This policy has substantial impact on our analysis.
- If CO_2 permits are not included in the cost base, but included in the electricity prices (due to the opportunity costs) then the NPV for coal is substantially higher than the NPV for gas.

Figure 7.3: Net present value with and without auctioning of CO_2 permits



Source: PwC analysis

- The longer the company receives the permits at no cost the higher the relative NPV of coal to gas would be. This can be seen in figure 7.4. If permits are at no cost for seven years or more after the project start, coal has a higher NPV than gas.
- This is because carbon costs are a very substantial part of total coal costs. Moreover, discounting of the cash flows gives a greater weight to the first years.
- In addition, it is interesting to note that with only four years of permits at no cost, the coal-fired power station has an NPV equal to zero.

Figure 7.4: Net present value and year of auctioning of CO_2 permits

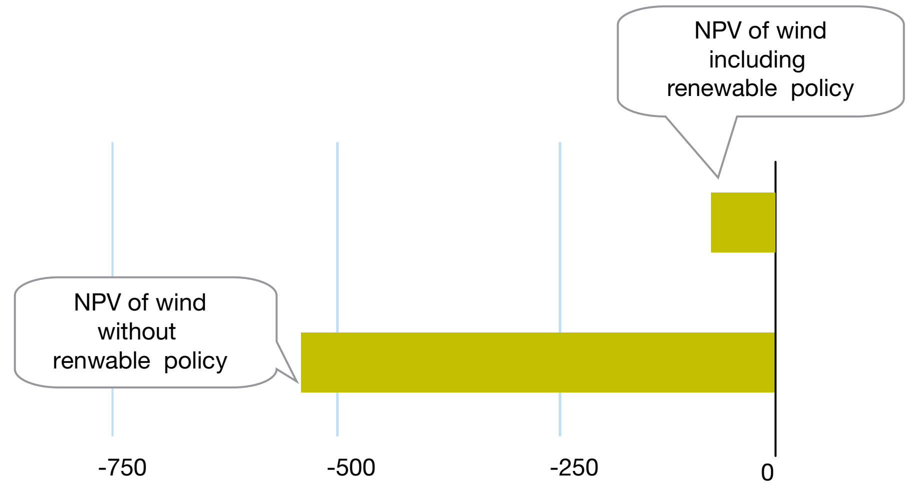
Source: PwC analysis

A

Without the stimulation policy of the Dutch government the Net Present Value of wind decreases significantly

- In the Netherlands the government stimulates the installation of new renewable production capacity. The two main financial instruments are the SDE and the Energie Investerings Aftrek ("EIA"). The EIA enables depreciation to be brought forward, thereby postponing tax payments.
- The SDE will start in April 2008. The SDE compensates the operator of renewable energy to the level where costs – including a return – can be recovered.
- Without the EIA and the SDE wind energy would not be profitable. The NPV for 1 MW would be - € 590k, compared to -€ 37k in the situation with the renewable energy policy.

Figure 7.5: Net present value with and without auctioning of CO_2 permits

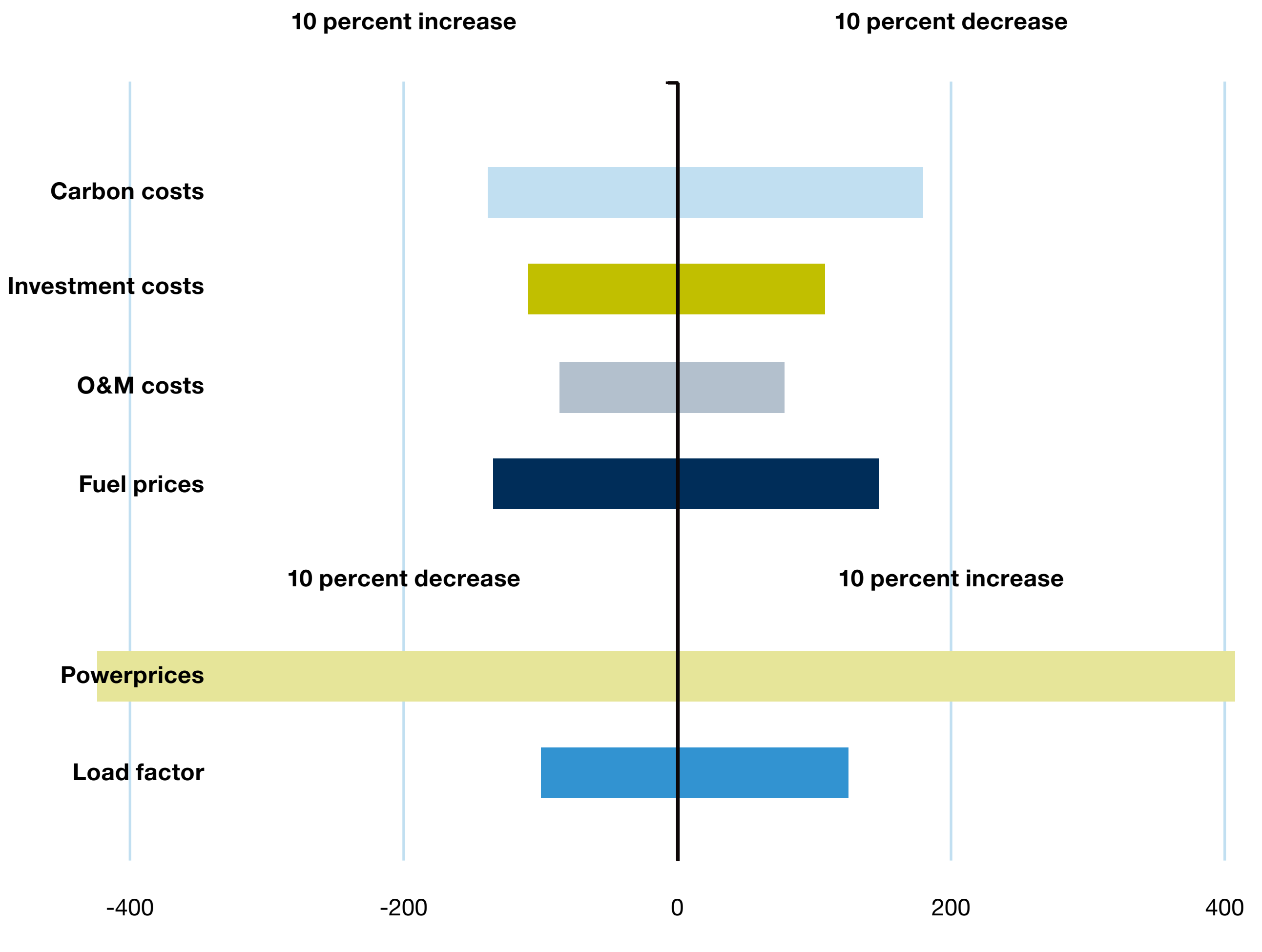


Source: PwC analysis

B

Coal: Power prices and carbon prices are the main value drivers

Figure 7.6: Sensitivity of coal results in the Base Case



Source: PwC analysis

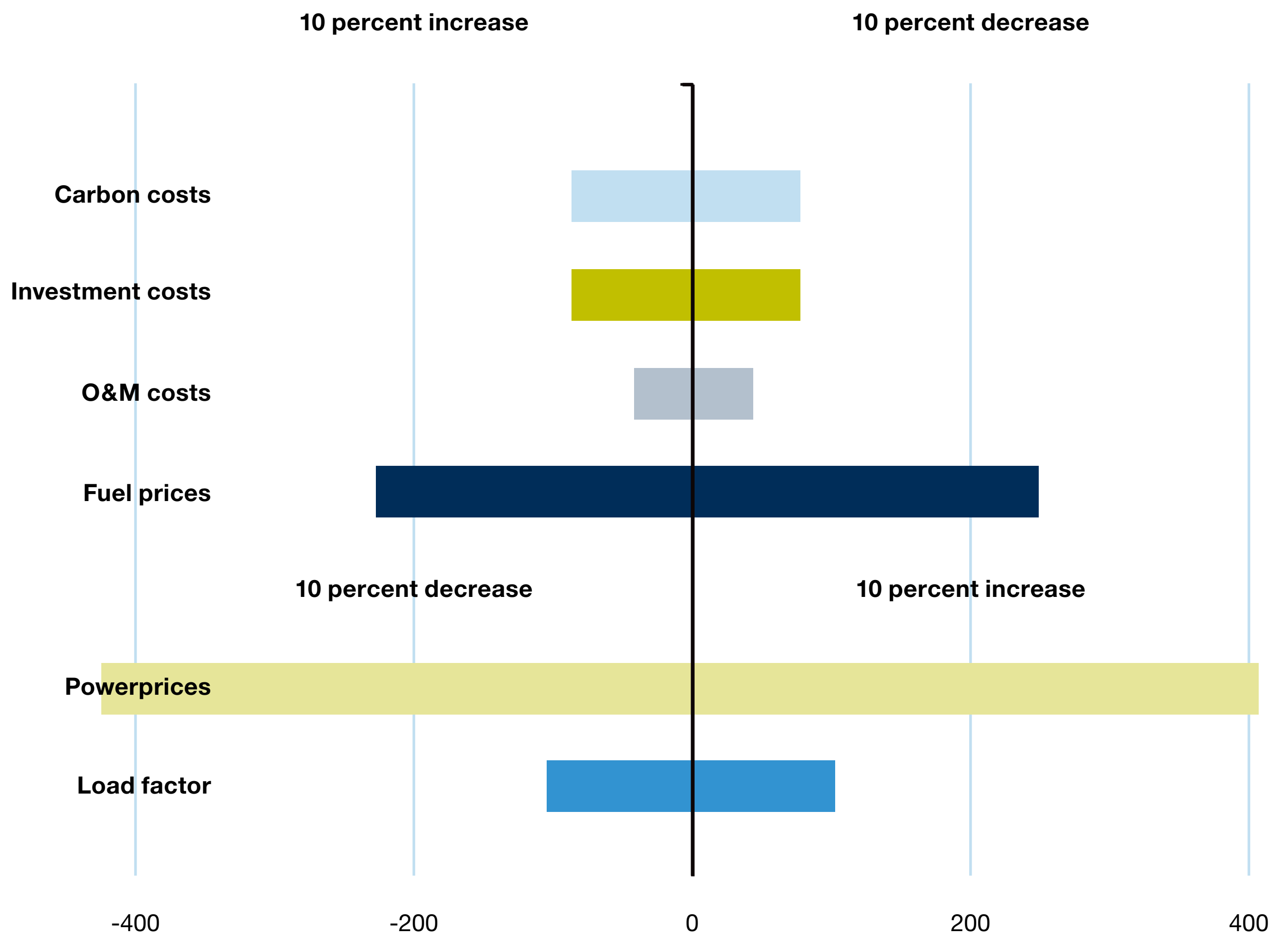
The sensitivity analysis shows that carbon costs, power prices and fuel costs are the main drivers for the financial performance of a coal-fired power plant. The effects of a small increase in load factor and O&M costs are limited.

If power prices increase by 10%, ceteris paribus, the coal-fired option has a positive NPV.

B

Gas: Power prices and fuel prices are the main value drivers

Figure 7.7: Sensitivity of gas results in the Base Case



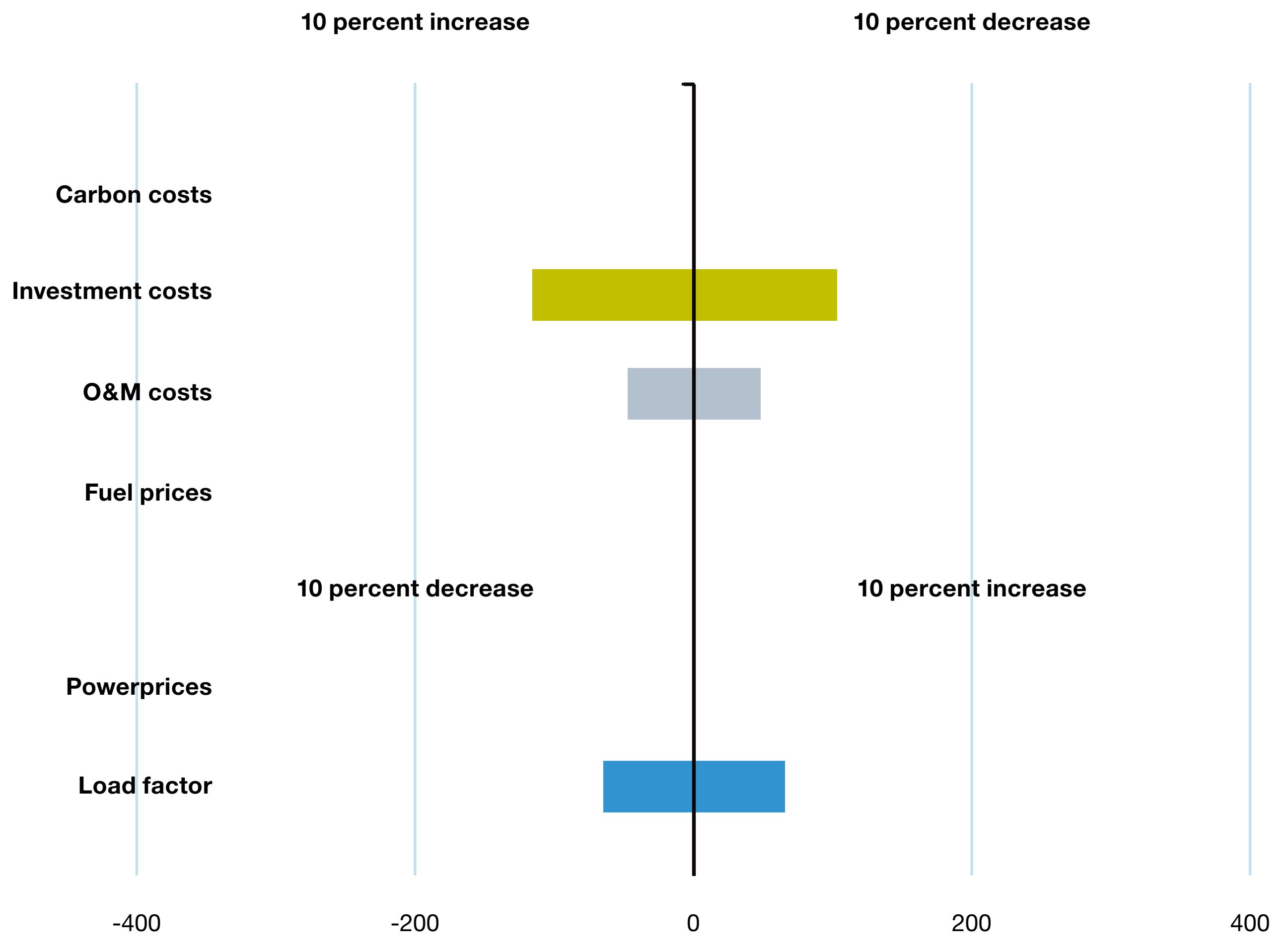
Source: PwC analysis

The sensitivity analysis shows that gas is more sensitive to the fuel price than coal. This is because fuel costs are a larger part of total costs. Carbon costs in contrary have less influence on the NPV of gas. As with coal, a change in power prices has a substantial impact on NPV (ceteris paribus).

B

Wind: Investment costs and load factor are the main value drivers

Figure 7.8: Sensitivity of wind results in the Base Case



Source: PwC analysis

The sensitivity analysis shows that the load factor and investment costs are the main value drivers for wind. Because the SDE energy subsidy guarantees a financial return, there are no effects of a change in power prices. O&M costs are the only adaptable value driver once a wind turbine is installed.

C

Bandwidth sensitivity analysis

- Based on publicly available literature we have defined a range for the major input variables. The ranges are summarised in the table.

Table 7.1: Bandwidths used in the sensitivity analysis

	Gas	Coal	Wind
WACC	4.21%-6.21%	4.21%-6.21%	4.21%-6.21%
Investment	€ 600-700	€ 1200-1300	€ 1237.5-1300
O&M fixed	€ 10-25	€ 24-46	€ 24
O&M variable	€ 0.5-3	€ 1.8-3.5	€ 24
Efficiency rate	56-60%	42-47%	24-26%*
Depreciation	15-30	30-35	15-20

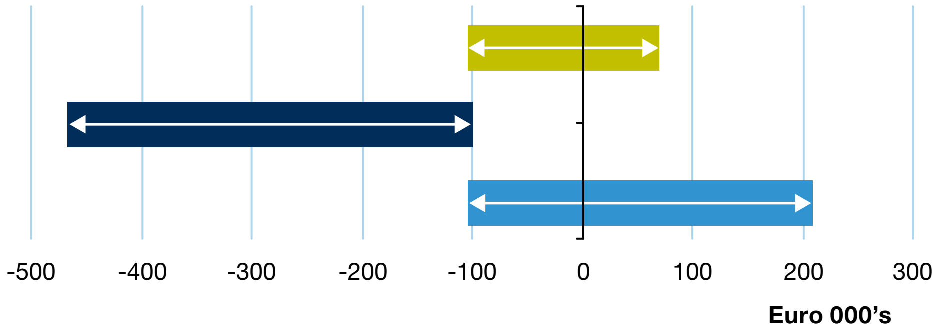
Source: PwC analysis

* *For wind this number represents the load factor.*

- In figure 7.9 on the right we have shown the most negative NPV and the most positive NPV for all three options. We have changed one variable at a time and not combined the various assumptions. The variable and fixed O&M costs estimates are taken together. In one case we have taken the upper limit of the range for the fixed and the lower for the variable costs. In the other case we have taken the upper range of the fixed costs and the lower for the variable.

- This analysis shows that our findings are robust. A change in one of the variables, excluding electricity prices, does not result in a change in the relative position of one of the options. Furthermore we find no overlap between gas and coal.

Figure 7.9: Bandwidths of net present value based on input variables



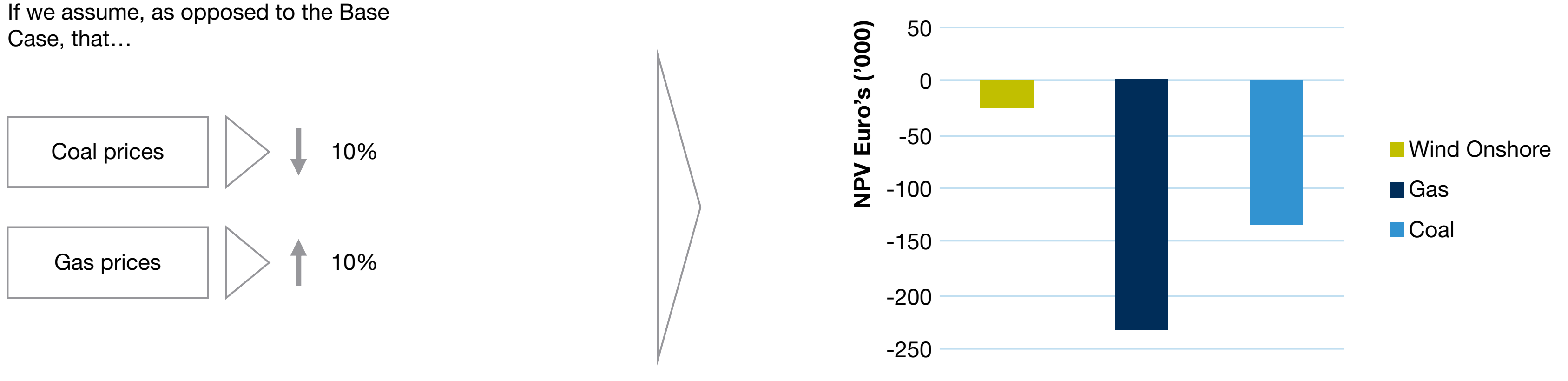
Source: PwC analysis

C

A different view on fuel price development has substantial consequences for the relative outcomes

Different view of global energy resources and security of supply has far-reaching consequences for the outcome…

Figure 7.10: NPV with different commodities price assumptions



Source: PwC analysis

If coal prices decrease 10% and gas prices increase 10% then, ceteris paribus, coal is relatively more attractive than gas.*

Both options however have negative NPV's.

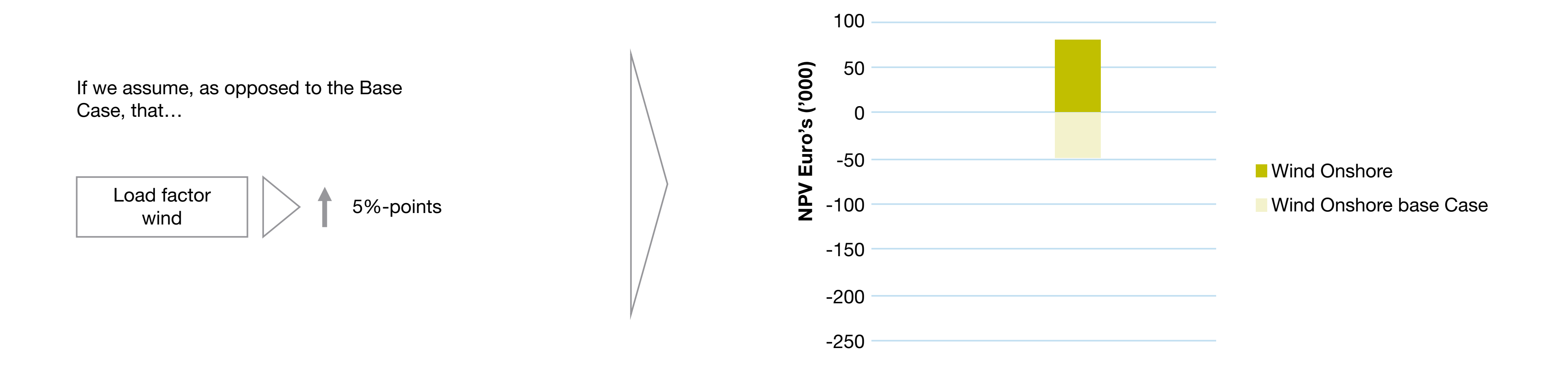
* *Please note that in this analysis 2nd order effects (e.g. the power price can be expected to increase) have been ignored.*

D

Increasing the load factor for wind has a positive effect on the NPV

When a higher load factors is used for wind the NPV increases …

Figure 7.11: NPV with different load factor assumption



Source: PwC analysis

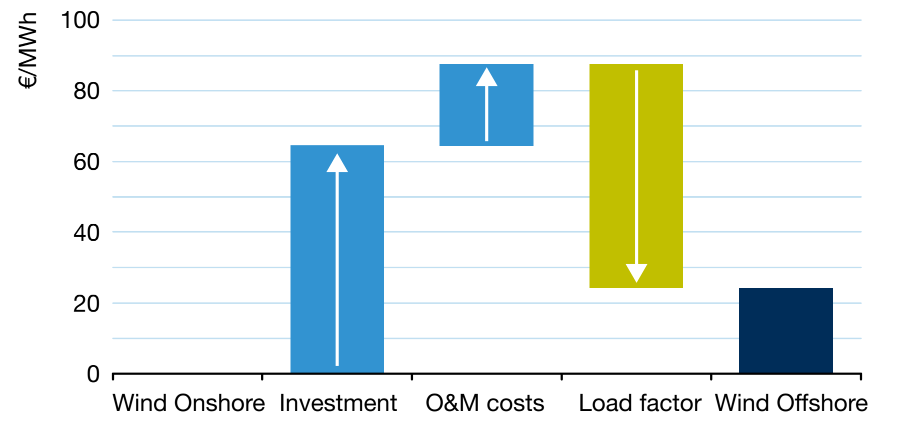
If the load factor for wind is increased by 5 percentage points then the NPV increases to € 96 k.

D

Wind offshore generates extra electricity but implies higher costs

- Currently there is one offshore wind park in the Netherlands (in the North Sea) and one park in construction. The capacity of the two together is about 230MW.
- There is a large potential for new wind parks in the North Sea. ECN scenario's estimate the potential for offshore wind energy at 6,000MW in 2020.*
- Compared to wind onshore wind offshore has multiple differences:
  - Investment costs and O&M costs are higher;
  - Load factor is higher; and
  - Subsidy (SDE) has not been determined yet.
- Given the fact that the SDE for wind offshore has not been set yet, it is not possible to calculate an NPV for wind offshore comparable to wind onshore.
- Therefore we have focused on the financial consequences of the main differences between onshore and offshore. The analysis has been based on current ECN estimates of the characteristics of offshore wind energy**.
- Figure 7.12 explains the difference between the costs of wind offshore and onshore, expressed in € per MWh.
  - Starting with the characteristics of wind onshore and only changing the investment costs to the ones of wind offshore (2200 €/MWh), implies an increase of the costs of electricity production by more than 60 €/MWh.
  - Taking into account the higher O&M costs implies an additional increase of the NPV of 23 €/MWh.
  - The higher load factor of wind offshore reduces the costs (about 50% more power production per MW). However the net costs of wind offshore remain about 25 €/MWh higher than wind offshore.

Figure 7.12: The cost difference in NPV of onshore and offshore decomposed



Source: PwC analysis

* *Source: ECN E-07-032: "Verkenning potentieel en kosten van klimaat en energiemaatregelen voor Schoon en Zuinig"*

** *Source: ECN E-07-069: "Technisch economische parameters van duurzame elektriciteitsopties in 2008-2009"*

Section 8
Integral assessment

From a financial economic analysis towards an overall investment decision (1/2)

- We have identified three main arguments that could lead to different investment considerations compared to our financial economic analysis:
  - The economic impact of 1MW is different to the impact of 1000MW. Therefore, the results from the marginal analysis can not directly be used to draw conclusions when the scale effect is taken into account.
  - Other non-economic arguments can tip the balance in favour of a particular generation option. The most common argument is security of supply and fuel diversification strategies given geopolitical tensions and uncertainties.
  - The technology that is used is more flexible in terms of fuel input (e.g. co-firing) or emissions (e.g. carbon capture options) than assumed.

Impact of 1MW versus 1000MW

- In the marginal analysis we compared the financial and economic consequences of building 1MW of the generation alternatives. This marginal analysis allows for an easy comparison of the options on a per MW and per MWh basis.
- However, in real life building 1MW power stations is not feasible. In the case of coal for example, power stations can have a capacity of 1000MW or more.
- In our marginal analysis we assume that building a marginal 1MW will not impact prices or the behaviour of players in the power market.
- We expect however that the results from our marginal analysis, mutatis mutandis, will apply when we scale up the investment options. There are a number of reasons why we believe this is a plausible assumption.
- First, the ECLIPSE model used by IPA decides to build additional gas-fired power stations to meet increases in demand. This new build is – according to the model – the least cost option of meeting increased demand.
- In addition, the IPA results do not show alternative generation investments, such as coal-fired power stations, even though the scale is not limited in the model. This suggests that for the system, additional gas-fired stations are the only economic viable investment choice.
- Second, in a competitive market the price is based on long run marginal costs. Our analysis shows that gas-fired power stations have the lowest long run marginal costs. Therefore, only power stations with equal or lower long run marginal costs will be economically feasible.*
- Third, we can scale the results in the 1MW analysis without assuming the impact of economies of scale. The technical characteristics we apply in the 1MW analysis are based on the technical specifications of a full-scale power station, taking into account scale efficiencies.
- Fourth, the addition of 1000 MW of capacity (instead of 1MW) will not provide the producer with market power that would allow prices to be influenced.
- However, power markets may not be perfectly competitive in the short run. The scope of our analysis has not allowed us to research this in detail. Therefore, we can not exclude the possibility that scaling up could influence prices and behaviour.

Security of supply and fuel diversification

- Even though the pure financial economic analysis may show a particular investment choice to be best, it may nevertheless be desirable to choose an alternative generation option. The Dutch power market is dominated by gas-fired generating capacity. It may desirable from a fuel diversification strategy to include other fuel sources for the production of electricity.
- In recent publications the European Commission** and the Energy Advisory Council (AER) of the Dutch Government*** have both indicated the need from a national perspective to increase security of supply and fuel diversification.
- Additionally, companies themselves may wish to diversify their generation portfolio and thus reduce their own exposure to a single fuel.

From a financial economic analysis towards an overall investment decision (2/2)

- Coal-fired power could improve security of supply. In contrast to natural gas, global coal reserves are widely dispersed and can also be bought from politically stable countries. European markets are largely dependent on natural gas from Russia.
- With good access to ports, the supply of coal in the Netherlands looks stable and predictable.
- Simultaneously, given the Dutch natural gas reserves and the strategy of Gasunie to become the gas centre of Europe, it is plausible to expect gas supplies to remain stable and predictable in the Netherlands.
- Further in this report we analyse the shadow price associated with this diversification strategy in more detail.

Choice of technology

- In our analysis we have assumed straight-forward single fuel usage. However, both the gas and coal options allow for additional types of fuel to be used for the production of electricity.
- In the case of gas-fired power stations, bio gas or liquefied bio fats could be used as an additional fuel source with positive potential environmental side effects.
- In the case of coal-fired power stations additional bio mass could be used to fuel the generation unit, with potentially similar positive environmental effects.
- For both coal and gas-fired generation it is possible to use the heat and steam for industrial purposes or residential heating. This improves the overall efficiency and hence reduces the CO_2 emissions.
- We have not included the economic and financial impact of carbon capture opportunities. The actual costs of this technology are difficult to estimate and there remains uncertainty with regard to the actual implementation. In Section 9 we analyse the potential impact of these options in more detail.

* *See Appendix D for a discussion of long run marginal cost pricing*

** *Source: European Commission (2008), "Explanatory memorandum of the third package"*

****Source: AER (2008), "Brandstofmix in beweging"*

Choosing one of the next-best production alternatives implies paying a shadow price

- The decision to invest in a second-best alternative from a pure economic perspective, such as coal or wind in our analysis, implies extra costs. These costs can be regarded as the shadow price that is paid for this uneconomic choice. This shadow price can be seen as the additional cost to society of choosing coal or wind.

- We have analysed the economic cost of the choice for coal-fired generation. The financial difference can be interpreted as the shadow price of security of supply or fuel diversification. This shadow price for 1 MW of coal is € 257k for the whole time horizon of our analysis (2030).

- We have also analysed the shadow price for wind, compared to gas. Wind has a lower load factor than gas or coal. In order to make wind comparable to gas the NPV has been adjusted for this lower load factor. This leads to a shadow price of € 134k for wind, compared to the output of 1 MW of gas.

- Both shadow prices, for coal as well as for wind, have been determined from the point of view from the investor. External costs and benefits of both options are not included in these calculations.

Table 8.1: Shadow price analysis coal and wind from investors point of view

	Coal	Wind (load factor adjusted)
NPV difference relative to gas on a MW basis	- € 257,000	- € 134,000

Source: PwC analysis

Section 9

Environmental upsides to fossil fuel fired power stations

The use of biomass in coal and gas-fired power stations seems less attractive than our plain vanilla gas-fired option (1/2)

- Power stations for gas and coal also have the ability for co-firing with biomass. The biomass usually requires some pre-treatment before it can be used in power stations. In general it can be said that the use of biomass in coal-fired power stations requires less treatment before than the use in a CCGT. The SDE for this so called large-scale biomass has not been determined yet.

- The use of biomass provides advantages with regard to climate change. Less allowances need to be obtained if the stations make use of biomass. For our analysis we have used data from ECN in order to assess the possible impact of biomass.*

- The use of biomass in fossil fuel fired power stations can have, inter alia, the following cost implications:

  - Additional investments power station;
  - Additional investments for infrastructure;
  - Additional costs for operation and maintenance;
  - Costs of the biomass; and
  - Changes in efficiency.

- For the use of biogas we have analysed the maximum allowable costs of the biogas input in order to have the same NPV as the basic natural gas option. This value is strongly related to the gas price. Ignoring additional investments to make CCGT suitable for co-firing, the maximum price for biogas is around 7 €/GJ in the Base Case. It may be clear that higher gas prices allow for higher allowable prices for biomass.

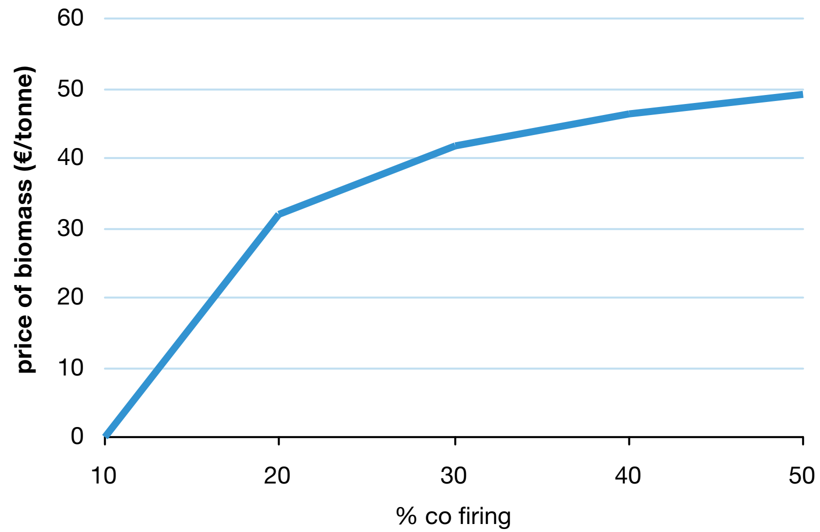
- For comparison ECN assumes a price for bio fuel of 9.4 €/GJ, higher than the allowable price from our analysis. Since no SDE has been set yet for large scale biomass the calculation of the NPV is not possible yet.

* *Source: "Inzet van biomassa in centrales voor de opwekking van elektriciteit", ECN-C-05-082*

The use of biomass in coal and gas-fired power stations seems less attractive than our plain vanilla gas-fired option (2/2)

- For the use of biomass in coal-fired power stations several kinds of fuel are possible. The report of ECN analyses the use of wood pellets, bio-oil, agro residue, and waste wood. Each option has its own characteristics with consequences for investments, operation and maintenance and fuel costs.
- Since the SDE for large scale biomass has not been set yet, a calculation of the NPV comparable to wind is not possible. Important parameters in the financial and environmental consequences of biomass are the amount of co firing, the price of the biomass and the sustainability of the biomass.
- We have analysed for which combinations of co firing and costs of biomass the NPV becomes equal to gas. In this analysis additional investments and O&M costs and eventual additional government subsidies have been ignored.
- Figure 9.1 shows the results. In the case of 10% co firing and no additional costs for biomass the costs would be comparable to gas. If the amount of co-firing increases, higher prices for obtaining the biomass are allowed.
- The ECN report mentions costs for biomass to be used in coal-fired power stations between 40 and 100 Euro/tonne. Figure 9.1 shows that with a price of 40 Euro per tonne, the percentage of co firing should be about 30% in order to obtain the same NPV as for gas. This amount of co firing is above the current ranges of co firing. Furthermore, it is important to be aware that the picture does not involve likely extra investment and O&M costs.

Figure 9.1: At what price of biomass is the NPV of coal-fired power stations with co firing equal to CCGT?



Source: PwC analysis.

Possibilities for the use of heat should be considered, however this requires thorough location specific analysis

- Gas and coal stations produce heat besides electricity. In the Netherlands, it is common that this heat is used for heating of industrial processes and buildings/houses. The use of heat has environmental advantages since it avoids the use of natural gas to produce the heat.

- The use of heat from power stations has various implications for the financial performance of a power station:

  - The delivery of heat generates extra revenues;

  - The delivery of heat requires extra infrastructure with associated O&M and capital costs;

  - Sometimes the delivery of heat reduces the net electric efficiency; and

  - The use of heat can reduce the flexibility of operation.

- In general it can be said that the applicability of cogeneration for coal is more difficult. This is related to the following:

  - Due to the larger scale of coal-fired stations compared to gas, coal requires a larger amount of heat demand at location; and

  - Infrastructure of gas in the Netherlands is more extensive for natural gas. Therefore in general, finding a suitable location for gas-fired power station near heat demand shows more options.

- A financial analysis of the consequences of supply of heat involves a detailed financial analysis of the extra costs and revenues. This analysis is also very situation and location dependent. This goes beyond the scope of our analysis.

Carbon capture and storage may become an option in the longer run

- Carbon capture and storage can be used to reduce the CO_2 emissions from fossil fuel fired power stations.
- CCS is not yet available for large scale power plants, demonstration projects at a smaller scale are being carried out. Multiple pilot projects and demonstration plants are in preparation, however for nearly all planned demonstration projects the date of potential CCS operation is not before 2012.
- The new coal-fired power stations to be built in the Netherlands are reported to be Capture ready. This means that in the construction of the plant, the possibility of adding a CO_2 capture installation in the future is left open. If CCS becomes commercially attractive there is the physical possibility to add this installation.
- Adding CCS to fossil fuel fired power stations has, inter alia, the following financial consequences:
    - Additional investments for the CCS installation;
    - Additional operation and maintenance costs;
    - Reduction in carbon costs; and
    - Reduction of the efficiency.
- When it comes to implementation of CCS, the liability for stored CO_2 is an other important aspect.
- Generally, it can be said that CCS becomes attractive when the value of the CO_2 allowances becomes higher than the costs of CCS. Large cost ranges can be found in literature. The IPCC special report over CCS (2005) shows a range of 30 to 70 dollar per tonne of CO_2, the EC publication "European CO_2 Capture and Storage projects" shows a range of 50-60 €/tonne CO_2.*
- These ranges are on average above the level of the CO_2 price assumed in our analysis.
- If the costs of CCS for a coal-fired power stations are equal to the value of the allowances, the NPV for a coal-fired power station with CCS would more or less be equal to the costs of a coal-fired power station without CCS.
- However, in our analysis we found a negative NPV for coal. Therefore we have analysed under which conditions the NPV of a coal-fired power station with CCS reaches the same NPV as the CCGT in our basic analysis. Analysis shows that the costs of CCS should be about 3-5 €/tonne CO_2 below the price of the CO_2 allowances to make up that difference.

* *Source: European Energy Review, Marc h/April 2008, page 39; IPCC 2005, Caron Dioxide Capture and Storage.*

Appendix A

Marginal analysis under alternative Low Case, High Case, and Greenpeace scenario’s

Greenpeace scenario: key assumptions

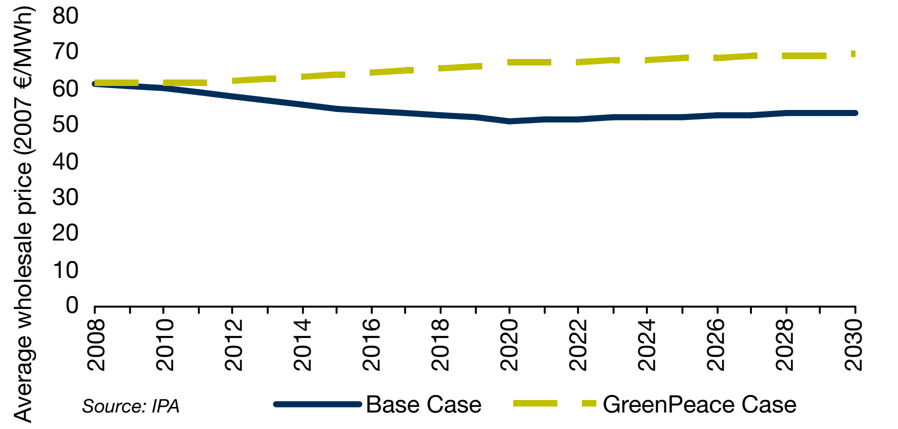
	IPA base case	Greenpeace changes relative to the IPA base case
Peak & energy demand	Growth rates of 2% applied to both peak and energy demand.	Growth rates of -0.26% within 2008-2020 and -0.64% within 2021-2030 are applied to peak and energy demand.
Commodity prices	See previous slides for commodity price development assumptions in IPA Base Case.	Base Case commodity prices are fixed at their 2008 levels in real terms. However CO_2 increasing to 74 €/tonne (2007 prices).
Capital expenditure for new build wind	Capital expenditure remains constant over time period.	Capital expenditure for new build wind is assumed to fall at a rate of 2.1% per annum within 2008-2030*.
Availability of new build wind	New build wind is assumed to be available 25% of the time.	Monthly average availability of new build wind plant is assumed to rise from 25% in 2008 to 30% in 2020-2030.
Reserve margin contribution	Annual average reserve margin contribution of new build wind plant is 15%.	Annual average reserve margin contribution of new build wind plant is assumed to rise from 15% in 2008 to 25% in 2020-2030.

[1] *In the IPA low case a 2% reduction per annum is assumed.*

Results Greenpeace scenario

- The base load power price is higher in the Greenpeace case than in the IPA Base Case. A sharp increase in carbon prices and relatively high commodity prices are the main reasons for this higher price.
- The Greenpeace assumptions result in a lot of new build wind.

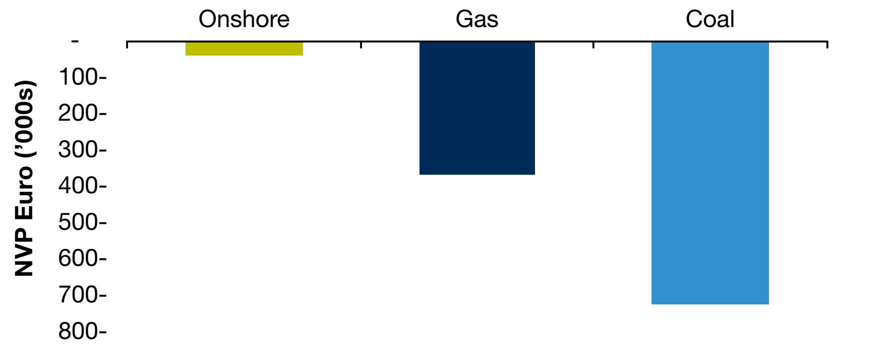
Figure A.1: Projection of electricity prices in the Greenpeace and base case



Source: IPA

- The assumptions in the Greenpeace scenario result in a negative NPV for both gas and coal. Higher carbon costs compared to the Base Case is the driver behind this result.
- Capital costs for wind decrease annually in the Greenpeace scenario. An investment in 2008 therefore has an NPV that is € 10k higher than in the Base Case.

Figure A.2: NPV in the Greenpeace scenario

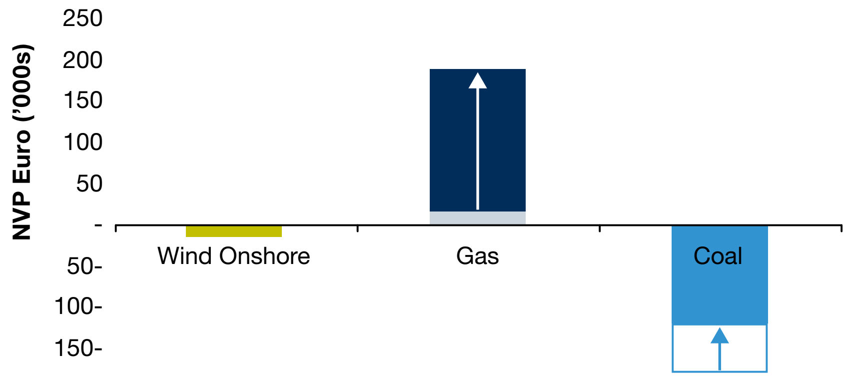


Source: PwC analysis

Results of the High and Low Case

- In the Low Case power and commodities prices are substantially lower than in the Base Case. The gas price decreases the most.
- The power price stays below the SDE subsidy per kWh. Therefore there is no change for wind compared to the base case.
- This results in an NPV increase for both gas and coal, with gas profiting most.

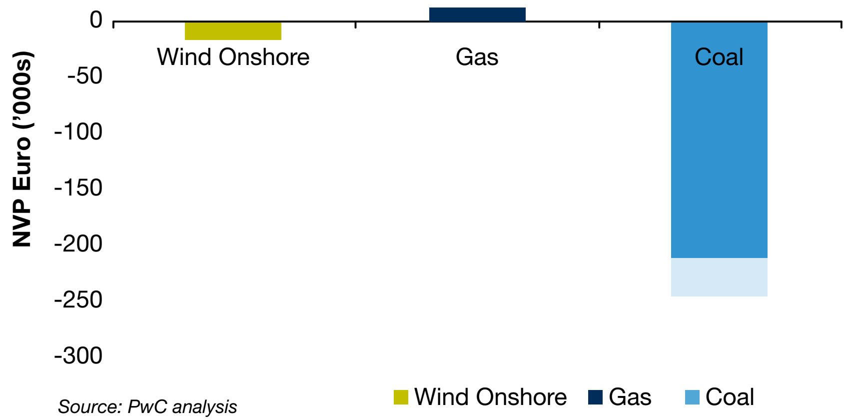
Figure A.3: NPV in the low case compared to the base case



Source: PwC analysis

- In the High Case power and commodities prices are higher. This has a very limited effect on the NPV of gas.
- As with the Low Case, the power price stays below the SDE subsidy per kWh. Therefore, there is no change compared to the Base Case.
- The NPV of coal changes from –€ 250k to –€ 240k.

Figure A.4: NPV in the high case compared to the base case



Source: PwC analysis

Appendix B

Basic input data and assumptions

Input assumptions used in previous analyses

- Our results depend on the underlying assumptions about costs and future prices. In this section we discuss the results of a sanity check of the data used in our analyses. We have performed a literature review on recent investment analyses.
- In the last years we have seen a sharp increase in construction costs. Due to worldwide increased demand for commodities the costs of building a power plant have risen sharply. The President of Siemens Power Generation Group, Randy H. Zwirn, estimated that prices had risen with 25 to 30 percent in the period from the end of 2005 to July 2007.* This illustrates that our assumptions are very sensitive to current market developments.
- Where the costs used in our analysis differed substantially from estimates used in other studies we have used these estimates in the sensitivity analysis.
- When comparing the O&M costs that IPA uses and the data from the IEA the numbers of IPA are higher. This number is not substantially higher as IEA assumes lower efficiency rates. The numbers in table B.1. are inflated from 2003 with an assumed inflation rate of 2%.

Tabel B.1: Overview of input assumptions used in the literature

	IPA	DTI/Redpoint	IEA	CE
Capital Coast (€/KW)	€ 672	£ 440	€ 540	€ 525
Variable O&M costs (€/MWh)	€ 0.6	£ 2	€ 1.62	€ 1.50
Fixed O&M costs (€/KW)	€ 26.1	£ 7.0	€ 17.67	€ 14
Efficiency	58% (LHV)	58% (LHV)	55% (LHV)	58% (LHV)

	IPA	DTI/Redpoint	IEA	CE
Capital Coast (€/KW)	€ 1,285	£ 1,030-1,069	€ 1,190	€ 1,100
Variable O&M costs (€/MWh)	€ 3.5	£ 1.2-2.0	€ 3.6	€ 2.0
Fixed O&M costs (€/KW)	€ 39.3	£ 19-50	€ 26.6	€ 20.0
Efficiency	45% (LHV)	45% (LHV)	40% (LHV)	47% (LHV

Sources: IPA, DTi, IEA, CE

* *"Costs Surge for Building Power Plants", The New York Times, July 10, 2007*

CE, "Welke nieuwe energiecentrale in Nederland?", november 2006

ECN (2007), "Estimating Costs of Operation & Maintenance for Offshore Wind Farms"

ECN (2008), "Technisch-economische parameters van duurzame elektriciteitsopties in 2008-2009"

IEA (2003), "Emission trading and its possible impacts on investment decision in the power sector"

DTI (2006), "Energy review", available at http://www.berr.gov.uk/energy/review/

Appendix C
Discount rate

In our analysis we use a real discount rate of 5.28% for all projects

- We have assumed that the projects are financed with 30% debt and 70% equity. The cost of debt is set at a pre-tax rate of 7% while we use a post-tax nominal equity rate of 12.2%. The nominal post-tax WACC with these assumptions is 7.31%. The assumed inflation rate is 2% resulting in a real post-tax WACC of 5.21%. These numbers are the same as those used by the Department of Trade and Industry (DTI) in its Energy Review.*

In reality the costs of capital may differ

- The WACC used in the analysis is the same for all generation possibilities. In reality the WACC will differ from project to project. From an investor perspective the risks may differ, therefore justifying different returns for the different options.

- It is difficult to get a good estimate of project specific WACC's for the projects. The costs of debt can be obtained from agreements with the banks. The cost of equity can only be estimated precisely by looking at publicly traded companies. Unfortunately, no company we know only operates a specific type of power plant. Therefore, we have to rely on the costs of equity of utilities and demanded project returns of investors.

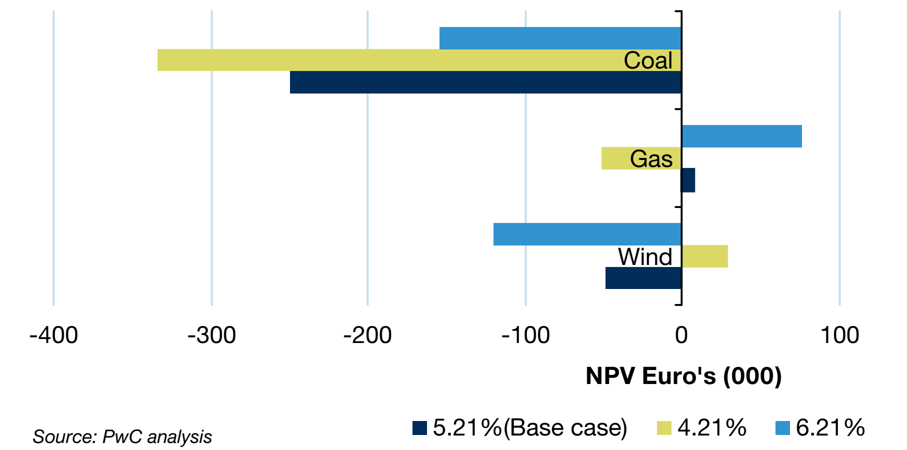
WACC Wind

In the computation of the SDE energy subsidy, the technical advisor to the Ministry of Economic Affairs, ECN, has used a slightly lower WACC than we do in this report. This explains why our results show a negative NPV for wind onshore. Our input assumptions are generally the same as ECN's. The investment subsidy is calculated in such a way that the NPV of a project would be nil. When a higher WACC is used the NPV becomes by definition negative.

Sensitivity analyses

In the sensitivity analysis we have used a lower and a higher WACC for all projects. This analysis shows that the relative ranking of the projects does not alter when different WACC's are used.

Figure C.1: NPV in the base case with different WACC assumptions



Source: PwC analysis

* *DTI (2006), "Energy review", available at http://www.berr.gov.uk/energy/review/*

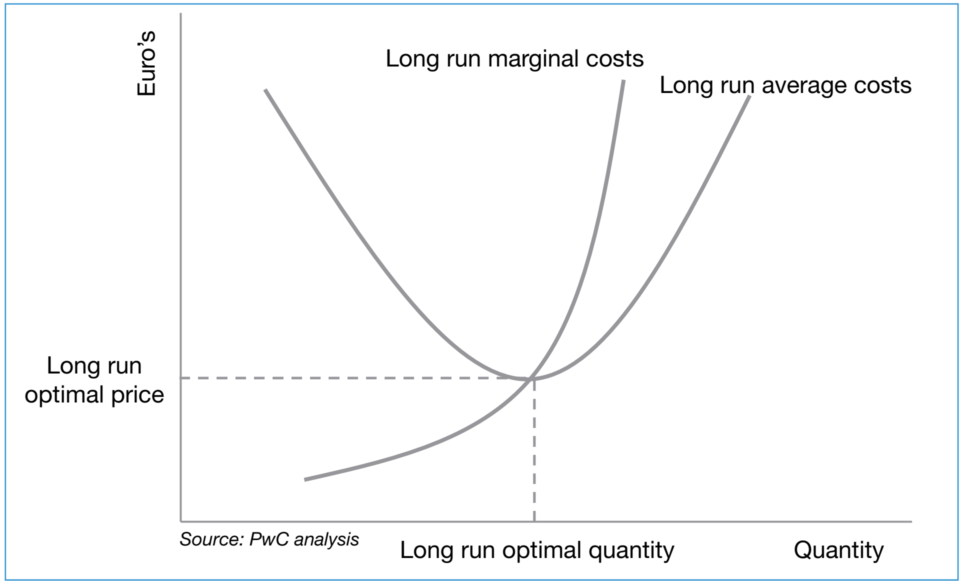
Appendix D
Long run marginal cost pricing

Long run marginal costs determine prices in a competitive market

- In the long run we assume that all factors of production are variable (labour, capital and land). Important here is the assumption that factors that are usually fixed in the short run, such as capital, can be changed. That is to say, it is possible to alter the capital structure of a firm, such as chosen technology or scale. A generic firm can therefore, in the long run:
  - Enter/exit an industry; and
  - Increase/decrease its scale.

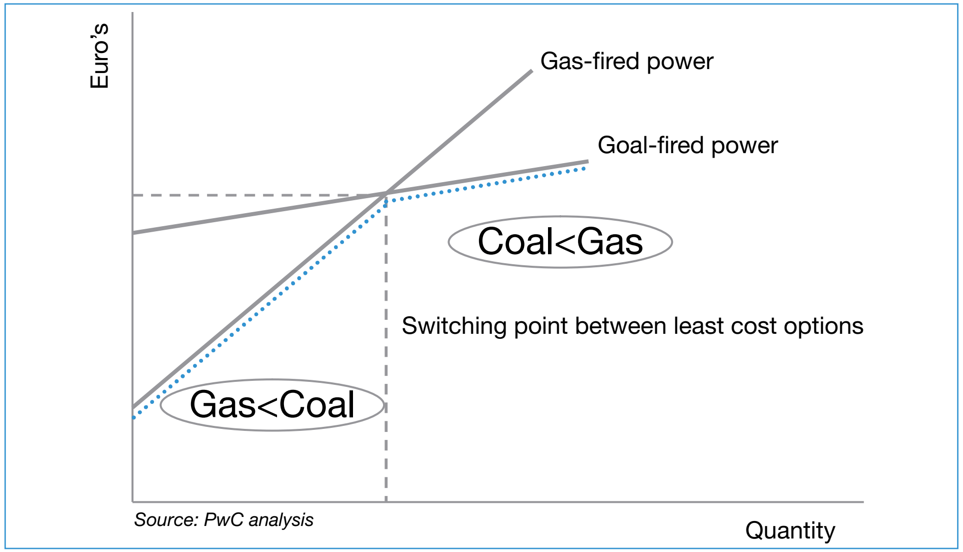
- It is these long run marginal costs (where long run average costs are minimised) that determines the price level in a competitive market. This is commonly referred to as LRMC pricing. A classic definition of LRMC for generation is the levelised cost of meeting an increase in demand over an extended period of time. This is essentially what ECLIPSE does.
- The choice to meet increases in demand over an extended time in generation is mainly between gas-fired and coal-fired alternatives. In the case of coal, the capital costs are higher than for gas. However, the variables costs, most notably fuel costs, tend to be lower.
- This is shown diagrammatically with two marginal cost curves for gas and coal. Where the two lines cross is a switching point for the least cost option.

Figure D.1: Long run marginal costs and long run average costs



Source: PwC analysis

Figure D.2: Fixed and variable costs for coal and gas



Source: PwC analysis

Appendix E
Glossary

Glossary of Terms and Abbreviations

Term	Definition
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
EEX	European Energy Exchange
ECX	European Carbon Exchange
ETS	Emission Trading Scheme
NEA	Dutch Emission Authority
NPV	Net Present Value
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
SDE	Stimulering Duurzame Elektriciteitsproductie
WACC	Weighted Average Cost of Capital

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