POWERFUL TARGETS:

Exploring the relative cost of meeting decarbonisation and renewables targets in the British power sector

AF-MERCADOS UK

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Innovation by experience

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Innovation by experience

Foreword *by Clare Spottiswoode CBE*

Clare Spottiswoode is perhaps best known for her role as Director General of Ofgas between 1993 and 1998, where she oversaw the transformation of the gas industry from a monopoly into an industry where every customer can choose who to buy their gas from.

Clare currently chairs Gas Strategies, and is European Chair and Non-Executive Director of Energy Solutions, a nuclear waste company, and as part of this role is also Chair of Magnox, she is a Non-Executive Director of G4S, a FTSE 100 company, of Enquest and Energetix.

She is an Independent Director of the Payments Council, ensuring that Banks co-operate in the interests of the general public, and was a member of the Independent Commission on Banking tasked with recommending what the Government should do to change the structure and regulation of banking. Her previous roles also include acting as the Policyholder Advocate for Aviva.

Awarded a CBE for services to industry in 1999 she holds degrees from Cambridge and Yale Universities in Maths and Economics, and has an honorary doctorate from Brunel.

This paper contributes to our understanding of how to achieve the UK's climate change targets in the power sector, and of the costs of taking different paths to do this.

It does not prescribe or recommend policy. Rather it looks at the lowest cost way of getting to the targets the UK has accepted for reducing its total greenhouse gas emissions by 80% by 2050.

In many ways the results are encouraging. Our modelling indicates that in order to meet our 2050 target for carbon reduction emissions for power we need to spend around 25% more than we would if we had no such target. To achieve exactly the same amount of carbon reduction – but with the renewable targets as well – would add around another 15%, or about 40% extra overall costs compared to no targets.

Without carbon dioxide reduction targets there would be no renewable or new nuclear. This illustrates the obvious point that carbon credits or other government policies are required to achieve power generation that is less carbon intensive.

If our only policy driver is to reduce carbon emissions, then the lowest cost way of meeting our emissions targets requires a mixture of gas and nuclear new build. Coal has no place in this least cost scenario – because of its emissions. Nor has wind, either onshore or offshore – because of its additional cost. To meet the UK's targets does require some offsetting by carbon capture and storage. This is a technology that is still in its infancy and is unproven.

It is only when we require renewables for their own sake – and not only to reduce carbon emissions – that wind, both offshore and onshore, becomes part of the generation mix. Even in this scenario solar power has no role because of its additional cost.

These are interesting conclusions. If we are concerned about cost, then renewables have no part to play in reducing greenhouse gas emissions by 80% before 2050. Rather it is gas and nuclear alone that creates the least cost mix.

What is clear is that current policies, under DECC's own central projections, are not delivering emissions reductions using the lowest cost means. Indeed according to this analysis, current policy is set on a relatively high cost path.

The model shows that the cost of having a renewables target over and above an emissions target alone is high. It is often not clear whether the aim of that policy is to reduce carbon dioxide emissions, or to deliver renewables for their own sake. Understanding the difference is key to understanding the costs to the British economy.

Given the economic impact, it is important that the case for renewables is made independently and cogently. There may be valid policy reasons to go for a costlier mix, but if this is the case, it needs to be articulated openly and honestly, giving stakeholders robust forecasts of the costs and benefits.

We hope that this paper encourages debate and sheds light in this important area of our lives.

Deciding our energy future

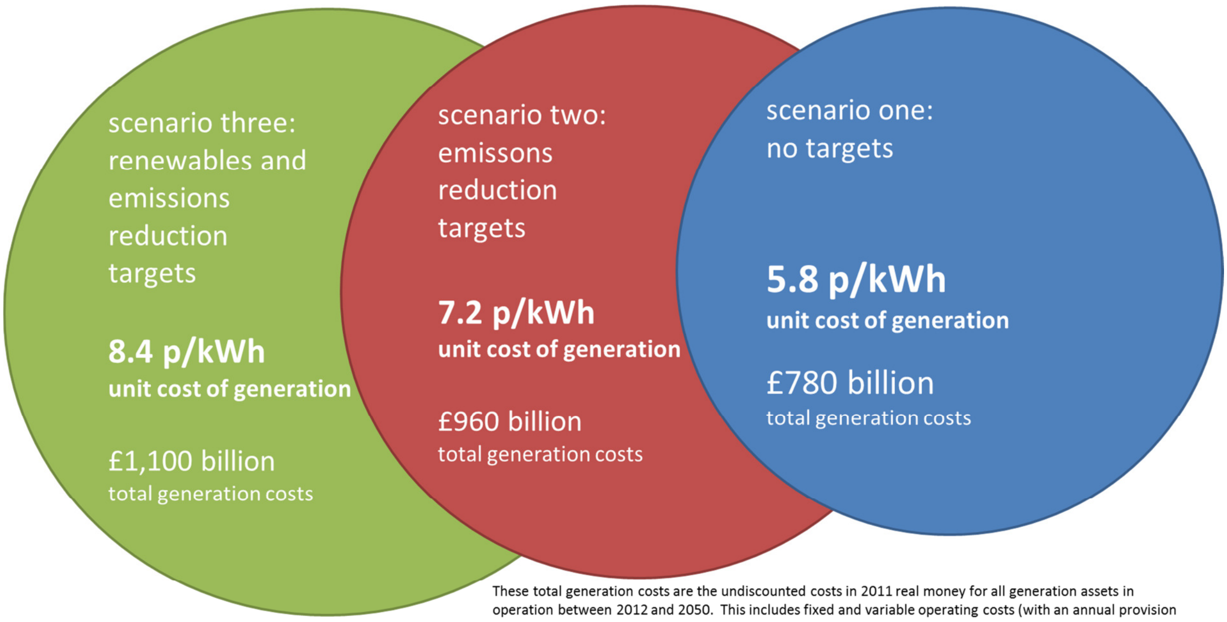
Great Britain is starting a significant program of investment in the power sector. Everyone in Britain will be affected by the decisions made now. It will affect our electricity bills and the competitiveness of our businesses for decades to come.

The power sector has challenging targets for carbon dioxide reduction and renewable electricity generation. In this paper, we look at the least cost way of meeting these targets. To do this, we modelled generation development out to 2050 with the goal to determine the cheapest way of meeting electricity demand under three policy scenarios:

- Scenario one established a reference case of the least cost way of meeting electricity demand without policy targets, including a capacity margin at peak to represent security of supply;
- Scenario two was identical to scenario one, with the additional requirement of meeting targets for significant reductions to power sector carbon dioxide emissions; and
- Scenario three was identical to scenario two, with the additional requirement of meeting renewable electricity generation targets.

We have excluded existing policy elements, like feed in tariffs and carbon prices, to allow the model to look purely at capital and operational costs in determining the combination of generation technologies with the lowest overall cost to 2050.

The total cost of generation in the period 2012-2050 in each scenario is:



These total generation costs are the undiscounted costs in 2011 real money for all generation assets in operation between 2012 and 2050. This includes fixed and variable operating costs (with an annual provision for waste and decommissioning for nuclear), and the annualised cost of repaying the capital cost for generation built after 2011. The unit cost is this total generation cost divided by demand.

There are a number of key conclusions that we draw from our simulation results:

- The scenarios show that the least cost way of meeting 2050 carbon dioxide emissions reduction targets is to do so without renewable electricity.
- They demonstrate the important role of nuclear generation and gas-fired generation if we are to meet our carbon dioxide emission reduction targets at least cost. In fact, gas has a significant role in all our scenarios.
- For the challenging 2050 emissions targets, using DECC technology cost projections, carbon capture and storage may be important, highlighting the need for greater development to fully understand and reduce the costs.
- Capital costs vary between scenarios. Considerably higher capital expenditure on generation is required in the next few years to meet the 2020 renewable electricity targets. In scenario one the capital spend is £28 billion by 2020, in scenario two it is slightly lower at £24 billion (as no new coal is built, unlike scenario one) and in scenario three the capital spend is considerably higher at £69 billion by 2020. This excludes the wider costs of grid reinforcement.
- Meeting both the renewables and emissions targets at least cost (scenario three) requires significant amounts of new nuclear, gas and wind. These technologies have sometimes struggled

to get planning permission. Policy makers need to make sure that these projects get approval, or we will all pay the cost of more expensive alternatives.

As with all projections, the modelling results should be interpreted with a degree of realism. In particular, the limitations to what this analysis covers include:

- All the scenarios consider the least cost ways to meet targets regardless of their political acceptability. If there is a policy decision to use more expensive technologies, the costs will be higher than shown.
- Clearly, as with any forecast, there is considerable uncertainty about the costs of different fuels, so the scenarios should be considered as comparative only (this is why scenario one is important as a reference case). In all three scenarios we used the same publicly available DECC central forecasts of fuel prices. If the cost of fossil fuels are higher or lower than DECC's forecast, the costs and fuel mix will change.
- Nuclear and renewables can help to hedge against the cost of the volatility in international fossil fuel markets. We haven't put any value on this hedge. The future price of gas is uncertain, and there is an argument that says with the advent of plentiful shale gas, the price and security of supply of gas is such that gas may be cheaper than the DECC price projections.
- We haven't included the costs of short term balancing or of reinforcing the grid to accommodate new generation. Only the immediate cost of connecting the new generation to the network and of ensuring enough generation capacity to securely meet peak demand is considered. Adding wider reinforcement costs would be expected to add to the cost of all scenarios. In particular the renewables scenario would be expected to be relatively higher because the resource tends to be further from demand centres and the overall capacity build is higher. As an example, in Project Discovery (2009) Ofgem estimated the overall cost of transmission and distribution investment in their Green Transition scenario as £53.4 billion by 2025 compared to £47.0 billion in their Slow Growth scenario (although this is not directly comparable to our scenarios).
- We didn't consider the impact of policy measures that are more ambitious than DECC's central demand assumptions. In particular, the electrification of heat and transport that has been proposed to help meet targets for the wider economy would increase electricity demand in scenarios two and three. By not changing the demand between scenarios, we hope to show the comparative costs of targets on the power sector in isolation.
- The technology operational and cost assumptions we used were based on Parsons Brinckerhoff's 2011 cost update report for DECC and ARUP's 2011 report on the deployment potential of renewable electricity for DECC. If technology matures at different rates than envisaged, the least cost mix of technologies may be different.
- There is a limit on onshore wind based on ARUP's 2011 report for DECC which considered planning limitations, and if that is relaxed the renewables targets cost less.

We prepared this paper because we feel that the debate on the costs of different energy futures often seems to be led by groups with vested interests. We wanted to give an independent perspective on the cost of targets, based on data from reputable sources. We also wanted to separate out the arguments for carbon dioxide emissions reduction and for renewable electricity. This paper is not "pro" or "anti" any particular technologies. It is certainly not a prediction of the future or a statement of all the possible costs. This paper does start to provide a factual basis to openly assess policy measures against their costs. Policy makers, including DECC, should consider publishing similar data themselves, so the full implications of any policies can be understood by all stakeholders.

At present the costs of carbon dioxide permits and of renewable generation support in our electricity bills are still low. In the future, the impact on bills will increase to support the increasing renewable generation and emissions reduction requirements. The renewable energy and emissions reduction targets are binding on the UK, but we feel the costs should be articulated clearly and compared to the alternatives. If there are policy reasons to go for a more expensive mix, they need to be dealt with openly and honestly. We do not see any benefit in pretending that the additional costs do not exist, or wishing them away by bold assumptions on efficiency gains (which could benefit any scenario).

There are no easy answers, but we hope that our analysis will help inform the debate by bringing some transparency. It is certainly not the end of the story. We would like to hear views on this paper, other conclusions that people have drawn from it, and suggestions for future topics of research.

Scenario one: no targets

Scenario one simply looked for the lowest cost generation mix, taking into account capital and operational costs. The requirement of the model was to meet projected demand and our de-rated capacity margin at peak (the capacity margin is used as a proxy for security of supply) – more detail on the model is provided in the background at the end of this paper. We have deliberately excluded all the incentives currently in the power market, to look at just the least cost investment and operational scenario to meet policy goals.

Scenario one provides a reference case that we can compare the other scenarios to. It will not meet UK climate change obligations, so is not a realistic policy option.

Figure 1: Capacity development for scenario one (GW)

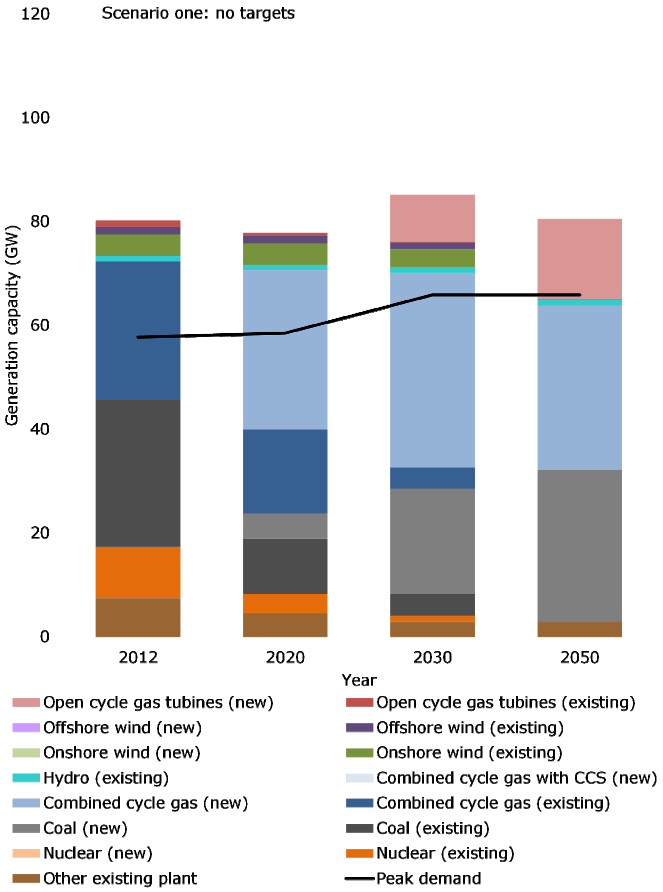
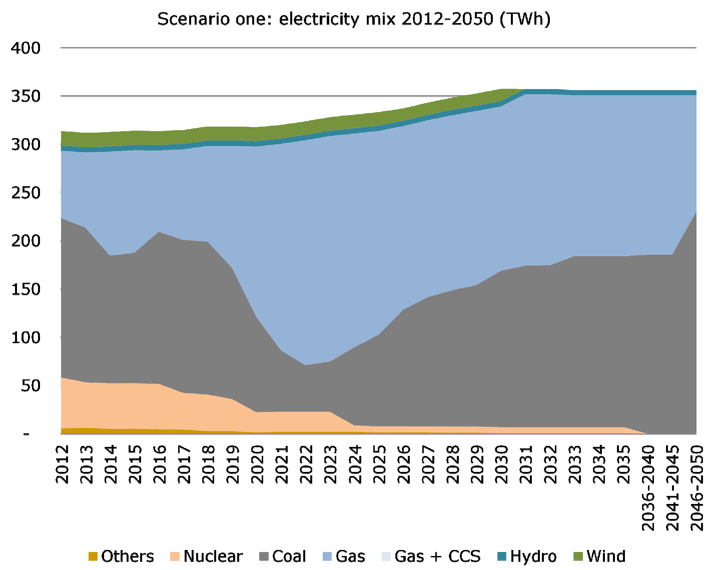


Figure 2: Generation 2012-2050 for scenario one



Results

The resulting mix of generating capacity is shown in Figure 1 and the electricity production for the period 2012-2050 is shown in Figure 2.

There are none of the existing policy mechanisms in this scenario, so there is no cost to the power sector associated with emitting carbon dioxide. The resulting mix of generation includes a large proportion of coal and gas, including combined cycle and open cycle gas turbines.

The blended unit cost of generating electricity in 2020 is 5.12 p/kWh. This blended unit cost is the sum of the fixed and variable generation costs, divided by the total demand. In the case of new generation built by the model, the fixed costs include the annualised cost of repaying the initial capital outlay.

The unit cost of electricity generation over the period 2012-2050 is 5.82 p/kWh.

Commentary

All models make assumptions and simplifications.

We have used DECC central estimates for fuel prices. In this scenario, the choice between coal and gas plant can be fairly finely balanced. In general in this scenario, open cycle gas plants (OCGT) are cheapest to build but most expensive to run, combined cycle gas plants (CCGT) cost a bit more to build and a bit less to run, and coal is more expensive than either gas plant to build but cheaper to run. Changes in relative gas or coal prices or introducing a requirement to buy carbon permits would have a significant impact on the proportions of coal and gas deemed optimal by the model.

Nuclear and renewables are both more expensive, so the simulated investment scenario does not include these technologies.

By using DECC's long term annual

price forecasts extended out to 2050 for coal and gas, we are not considering the impacts of shorter term price increases or decreases. For example, Ofgem's analysis suggests that recent rises in electricity bills have been largely due to wholesale gas price increases. On the other hand, some analysts' forward projections for gas prices are lower than DECC's and expect shale gas to have a downward pressure on prices.

By deliberately not considering the cost of carbon dioxide in this scenario, we are failing to recognise that other parts of the economy may suffer costs associated with climate change. Other analysis suggests that these costs may be higher than the cost of reducing carbon dioxide emissions.

However, this scenario is interesting. It shows that without the targets both coal and gas play a very important role. It also provides a reference scenario to which our other scenarios can be compared.

Scenario two: carbon dioxide targets

The UK has a legally binding target to reduce its total greenhouse gas emissions by 80% by 2050. To meet this target, the Committee on Climate Change considers that the power sector will need to reduce its emissions to around to 5 $MTCO_2$ by 2050, and has set out a trajectory to reach this point (Fourth Carbon Budget, 2010).

In scenario three, generation is chosen based on its capital and operational costs, as for scenario one, but with the added constraint that the overall generation mix must meet the Committee on Climate Change's emissions targets.

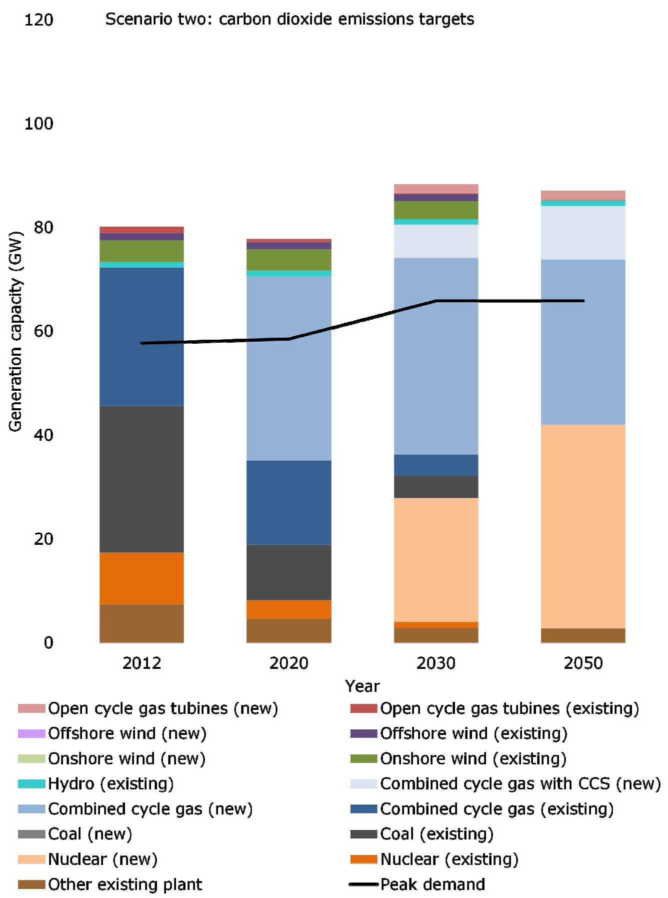
Results

The resulting mix of generating capacity is shown in Figure 3 and the electricity production for the period 2012-2050 is shown in Figure 4.

Out to 2020, the model builds gas-fired generation. The blended unit cost of electricity generation in 2020 is slightly higher than scenario one at 5.29 p/kWh.

However, after 2020, scenario two diverges more from scenario one. To meet the carbon dioxide reduction targets, the model builds nuclear generation and gas-fired generation, some of which is fitted with carbon capture and storage, requiring higher spend than scenario one. The blended unit cost of electricity generation over the period 2012-2050 is 7.17 p/kWh.

Figure 3: Capacity development for scenario two (GW)



Commentary

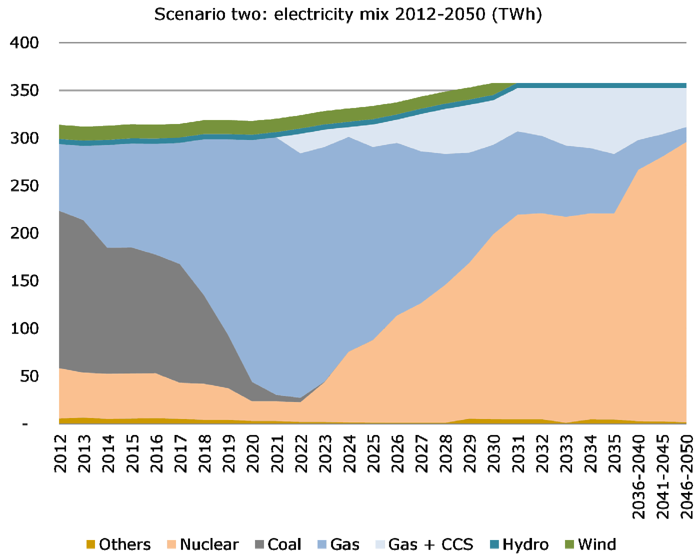
By placing a constraint on emissions, this scenario recognises the wider cost of carbon dioxide emissions.

This scenario does not build coal because of the emissions targets. This means it is not sensitive to the coal/gas cost differential as scenario one.

Carbon capture and storage (CCS) is currently at a relatively early stage of development. Much of the technology of individual components is proven in other fields, but there are few demonstrations of the full chain and scale. The economics and practicalities are less clear than for other technologies. As with other technologies, we have used the assumptions about long term costs and technological development from Parsons Brinckerhoff's 2011 cost update report for DECC.

While it achieves the carbon dioxide emissions reduction targets sought from the UK power sector, this scenario deliberately does not take into account the targets for renewable energy use that the UK has agreed at a European level. These targets are mandatory and member states failing to meet their renewable energy targets may face a financial penalty. At the moment it is

Figure 4: Generation 2012-2050 for scenario two



unknown if and how the Commission would make use of its penalty-imposing powers.

In this scenario over 20 GW of new nuclear is built by 2030, and nearly 40 GW by 2050. The model does not take into account the potential objections to nuclear that might prevent so much being built. It is worth emphasising that the model does include an annual provision for waste and decommissioning in the costs of nuclear based on Parsons Brinckerhoff's 2011 cost update report for DECC.

We have used the same DECC central demand projection as for scenario one, for comparison purposes. In the transition to a low carbon economy, there may be some decrease in power demand due to energy efficiency policies, but also an increase in power demand to help decarbonise heat and transport. We have not considered these potential changes to demand.

This scenario shows the importance of new nuclear and carbon capture and storage in delivering carbon dioxide savings at the lowest cost. It demonstrates that it is possible to meet the climate change target without a renewables target.

Scenario three: carbon dioxide and renewables targets

In scenario three, generation is chosen based on its capital and operational costs but with the constraint that the overall generation mix must meet both emissions targets and renewables targets. The UK has a binding target to generate 15% of energy (electricity, heat and transport) from renewable sources by 2020. The power sector is seen as having greater potential to contribute than other parts of the economy, so is expected to meet 30% of demand from renewables by 2020.

In this scenario the model is free to choose from a range of technologies to meet the renewables target, but is constrained from choosing more than 15,000 MW of onshore wind by 2020 and 20,000 MW by 2030. This is based on the ARUP report for DECC and reflects a view of the practical ceiling on developers getting successful planning applications.

Results

The resulting generating capacity mix is shown in Figure 5 and the electricity production for the period 2012-2050 is shown in Figure 6.

The mix of generation includes both offshore and onshore wind. From the data we used, wind had a lower cost than the other renewable alternatives available (for example, solar electricity). Onshore wind has considerably lower costs, but it was constrained based on the limits to deployment based on ARUP's 2011 report for DECC. The model builds the maximum amount of onshore wind allowed. Offshore wind meets the remainder of the target, and is a significant source of the extra costs associated with this scenario.

A significant proportion of nuclear and gas-fired generation (some with carbon capture and storage) is built, although less than scenario two. The overall capacity needed is higher, reflecting the variable nature of wind production and its lower expected contribution to peak demand.

The blended unit cost of electricity generation in 2020 is more expensive than the other scenarios at 6.73 p/kWh. The blended unit cost of electricity generation over the period 2012-2050 is 8.35 p/kWh.

It should be noted that these scenarios are based on least cost choices and do not reflect the costs to consumers of support mechanisms like feed in tariffs. As these currently include support to more expensive technologies, the real effect on consumer bills may be higher. The cost will depend on the detailed development of policy.

Figure 5: Capacity development for scenario three (GW)

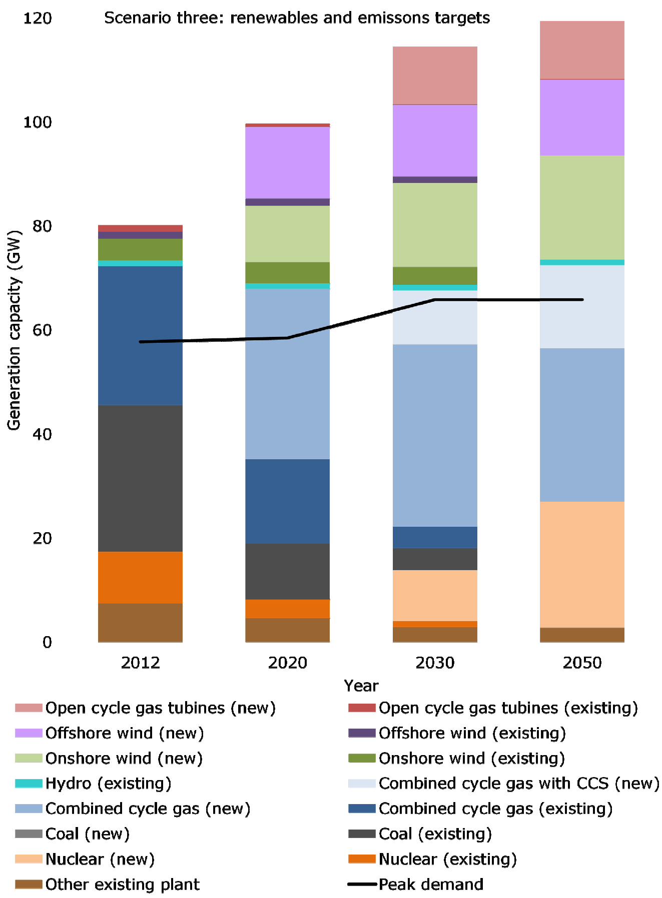
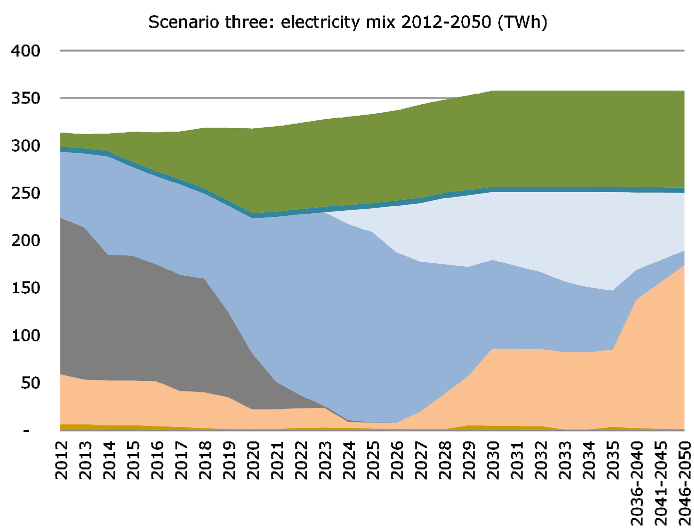


Figure 6: Generation in 2012-2050 for scenario three



Commentary

As noted under scenario two, renewables are more expensive than the other low carbon options, and so are used only up to the 30% target. A relaxation of the planning limits on onshore wind would result in more onshore wind and lower overall costs.

As for scenario one and two, we have used DECC's central demand projection. In reality, there may be an increase in power demand to help meet the renewables targets by using more electric heat and transport. Higher demand would mean more renewable generation was required to meet the 30% target.

This scenario includes a high proportion of wind generation. Although in general Britain has very good wind resource, output varies with wind speed. In all three scenarios, we require the model to build to a peak capacity margin taking into account the expected availability of generators at system peak (based on the National Grid Winter Outlook). The expected contribution of wind at peak is lower relative to conventional generation, and as a result the total required generation capacity is higher in this scenario than either of the other two, increasing the cost of this scenario. However, we did not include other costs of short term balancing, for example different operational costs for flexible fossil-fuelled plant that are ramping up or down more frequently.

Good wind resource is also often further from demand centres. The need to connect these remote regions, combined with the higher overall capacity required in this scenario, would require significant wider reinforcement investment in the grid that isn't shown in our analysis. We only include the immediate costs of connecting to the grid. For offshore wind, the costs of connection to the shore is included as part of the operational costs under the new offshore transmission charging regime. These costs are taken from ARUP's 2011 report for DECC.

With all our scenarios, we have used the assumptions on "first-of-a-kind" and "nth-of-a-kind" technology costs from Parsons Brinckerhoff's and ARUP's 2011 reports for DECC. If some renewable technologies achieve greater (or lower) cost savings than these reports suggest, then costs under this scenario will fall (or rise).

Comparing cost between scenarios

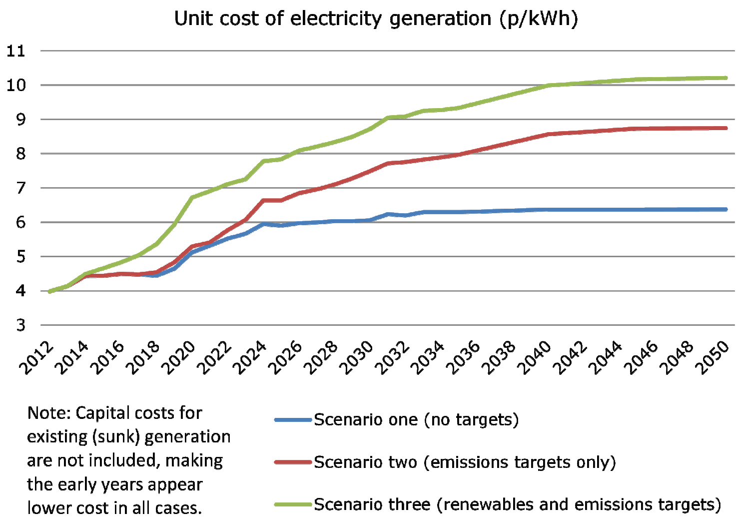
The costs in each of the three scenarios are shown in Figure 7.

These unit costs are based on the total cost of generation divided by the total demand in each year. The costs of generation include fixed and variable operating costs (with an annual provision for waste and decommissioning for nuclear), and the amortised capital cost of generation built after 2011. As we have not included the capital costs of existing (sunk) assets, the costs in the earlier years of the modelled period appear lower. However, this would only impact absolute values, not relative differences between scenarios.

The cost of scenario one becomes stable in the long term because we extend the DECC gas and coal price forecasts as constant values after 2030 and in scenario one the model is largely just replacing generation assets as they retire.

There is little difference between scenarios one and two in the earlier years. As the emissions reduction trajectory becomes more challenging, the cost difference between these two scenarios increases as low carbon generation is built to meet the increasingly challenging emissions targets.

Figure 7: Cost per unit in each scenario



Scenario three includes the 2020 renewables target. This means that the cost diverges from the other two scenarios earlier and remains higher.

Comparing carbon dioxide emissions between scenarios

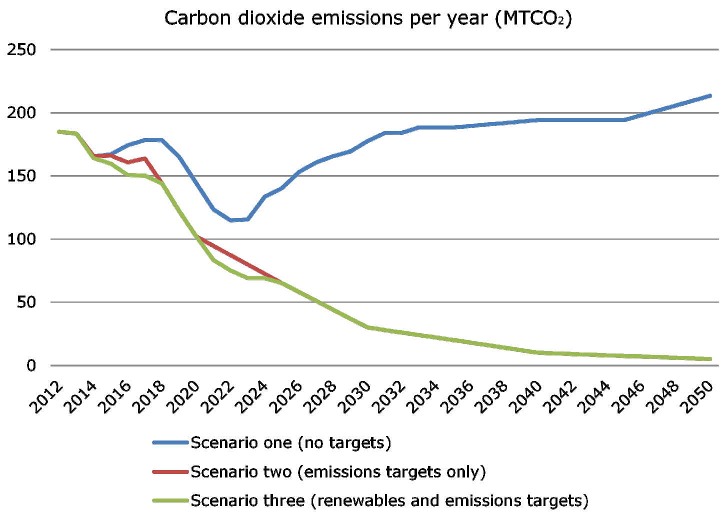
The emissions of carbon dioxide in each of the three scenarios are shown in Figure 8.

Emissions in scenario one are unconstrained, and depend mainly on the relative price of gas and coal in the DECC forecasts. The dip in the graph just shows that gas, which has lower carbon dioxide emissions than coal, is being used more in this period.

In scenario two and three, emissions are constrained to the Committee on Climate Change trajectory.

In broad terms, the key difference between scenario two and scenario three is that renewables replace some of the nuclear. There are minor differences in emissions between the two scenarios in given years, depending on plant operation.

Figure 8: Carbon dioxide emissions in each scenario



Background

Who we are

AF-Mercados EMI is a member of the AF group, a consultancy specialising in energy, environment, technology and industry with its head office in Sweden. The group employs 4,000 people internationally and is the sixth largest international design firm in power and the third largest international independent power engineering company (ENR 12/2010). Our services include techno-economic modelling and analysis of electricity markets and transmission systems. We advise governments, regulators and power companies.

Our modelling approach

Modelling was carried out using an AF-Mercados EMI proprietary model, ORDENA plus®. The model is an existing, well tested dynamic electricity market dispatch and long-term investment simulation model that has been used internationally in many markets.

In this paper we have used ORDENA plus® as a least cost dynamic investment model with the goal to minimise the capital and operational costs to 2050. There is a requirement to meet the forecast level of demand and a 10% de-rated peak capacity margin requirement for any given mix and amount of generation in each year of the simulation (the de-rated capacity margin is a proxy for the level of security of supply risk).

Our analysis has looked at the impact of different scenarios on investment and operational costs. We deliberately excluded Government interventions that affect generator costs and revenues (such as the emissions trading scheme, the renewables obligation, climate change levy, feed in tariffs, the requirement for new coal generation to include carbon capture and storage capability, proposals for contracts to support low carbon generation and an emissions performance standard).

Wherever possible we based our assumptions on DECC and National Grid data, or reports commissioned by

We did not model the short term costs of balancing the system, volatility in fuel prices, ramp restrictions, short term balancing costs, embedded generation, or any additional markets for peaking units. We also do not include the costs of wider grid reinforcement, although we do include the immediate costs of grid connection.

Our modelling was based on published and reputable sources of input data. Input assumptions for demand growth and fuel prices were taken from DECC (central 2011 data) and kept constant beyond the end of their forecasts. We used a representation of a load duration curve in each month. Data on existing plant, planned plant closures, and de-rating factors were taken from National Grid's Winter Outlook report (09/10 and 10/11). We made assumptions about plant closures where no definitive data was available. All current plant and new build is modelled with a fixed design lifetime. Generation investments are modelled as first-of-a-kind or nth-of-a-kind technologies (cheaper than first-of-a-kind), with operational and cost characteristics taken from Parsons Brinckerhoff's 2011 cost update report for DECC and ARUP's 2011 report for DECC on the deployment potential of renewable electricity. Seasonal availability for thermal generation was informed by DUKES statistics on load factors by fuel source and generation data from the ELEXON portal. The assumed available capacity factor used for wind generation is 28% for onshore wind (Ofgem ROC Register) and 37% for offshore wind (theoretical) and excluded seasonal variations.

Our target trajectories are based on the most recently developed pathway for how the UK intends to meet its targets. For carbon dioxide emissions we assumed these followed the Committee on Climate Change's trajectory for the effort required in the power sector (including a limit of 102 $MTCO_2$/year by the year 2020 and 5 $MTCO_2$/year by the year 2050). For renewable electricity, we considered a target of 30% of electricity generated from renewables by 2020, based on DECC's projections for how they expect the UK to meet its target for 15% of energy (including heat and transport) to be sourced from renewables. We constrained onshore wind to 15 GW in 2020 and 20 GW in 2030, informed by the ARUP's 2011 report for DECC which considered planning limitations on onshore wind development.

The model takes 2011 as the base year, and allows new build to commence from 2012 onwards taking into account the construction times for different technology.

We have assumed an average effective cost of capital of 10% in all scenarios. In reality, established technologies might have a lower cost of capital and less established technologies may have a higher cost of capital. We have not considered this in our analysis.

All figures are given in real 2011 prices, without considering inflation.

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