ARUP

Market Stabilisation Analysis: Enabling Investment in Established Low Carbon Electricity Generation

An Arup report for ScottishPower Renewables

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1 Executive Summary

Onshore wind is the lowest cost, low carbon generation technology which, in suitable locations, can be deployed at scale. Due to the capital intensive nature of onshore wind, combined with wholesale electricity market exposure, the investment case for onshore wind technology is unfavourable without a form of revenue stabilisation to mitigate market risk. Conversely, gas generation is somewhat protected from fluctuations in the wholesale price as it generally sets the wholesale price, therefore any reduction in its revenues as a result of a declining wholesale price in the UK is typically accompanied by a corresponding reduction in its operating cost (i.e. lower gas price). Therefore gas generation, benefits from a natural hedge to the wholesale market whereas onshore wind does not – if the wholesale price declines, the costs of low marginal cost renewable technologies such as onshore wind remain the same. Government recognised this issue at the outset of the Electricity Market Reform (EMR) programme and this formed part of the rationale for selecting the Contract for Difference (CfD) investment mechanism.[1] The structure of the CfD mechanism provides a stable revenue stream to a generator, with contracts auctioned through a competitive allocation process and only the most cost effective projects being successful.

A Market Stabilisation CfD seeks to offer a mechanism that could bring forward investment in onshore wind and level the playing field with gas generation, minimising the cost of progressing with decarbonisation.

A mechanism such as this would facilitate deployment of additional and necessary low carbon generation in a competitive and cost effective manner. However, a question remains as to what level of CfD strike price could be considered 'subsidy-free'.

Arup has undertaken analysis using two possible methodologies for estimating the potential Administrative Strike Price (ASP), which acts as a maximum price cap for the relevant technology for a Market Stabilisation CfD:

- **Method 1:** levelises potential revenues for onshore wind with a forecast of wholesale prices adjusted to address the effects of externalities (principally in relation to the costs of integrating renewables).
- **Method 2:** aligns the revenues for onshore wind with the cost required for a new build CCGT, adjusted for externalities (principally in relation to the costs of integrating renewables).

Method 1 provides revenue stabilisation to onshore wind aligned to the future revenue it could secure in the market, adjusted for externalities. Method 2, based on the levelised costs of a CCGT, provides onshore wind with the level of revenue that a new CCGT would require in order to be built, adjusted for externalities.

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48129/2176-emr-white-paper.pdf (Box 2 Page 28)

For Method 1, we have completed analysis of scenarios based on Government's assumptions for wholesale prices, along with Arup's capacity market and balancing mechanism modelling suite, in order to produce a view of the revenues available to new-build onshore wind generators. For Method 2, we have relied upon Government's own assumptions to produce levelised cost scenarios (save that we have used Arup's load factor estimate). A range of outputs from the two methodologies are shown below.

All costs and prices quoted in this report are expressed in 2012 prices unless stated otherwise.

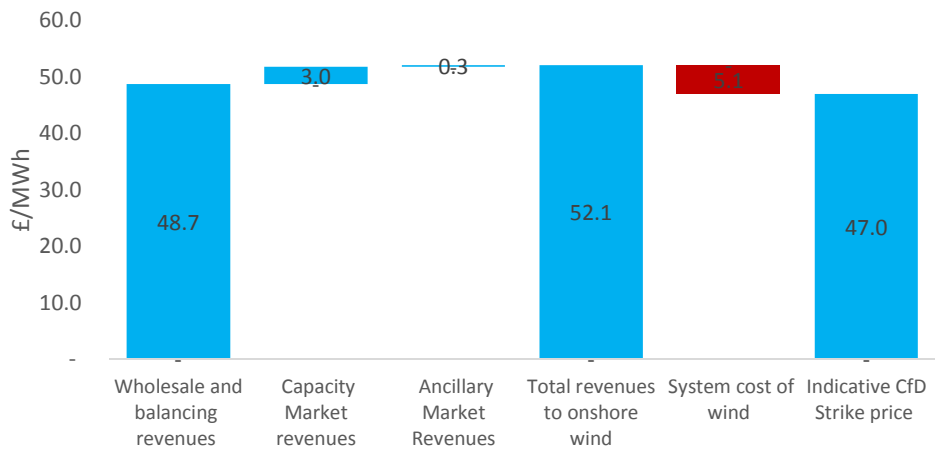

Figure 1: Method 1 ASP build-up in the Central scenario

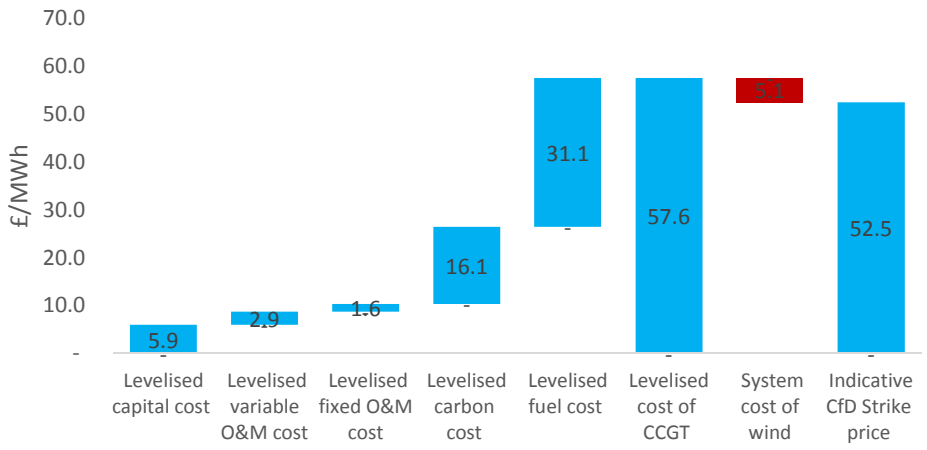

Figure 2: Method 2 ASP build-up in the Central scenario

The resulting indicative CfD ASPs arising from the Methods range between **£47.0/MWh** and **£52.5MWh**, corresponding to a spread of £5.5/MWh. The Central case outlined in the analysis above is based on BEIS's 2016 Central price assumptions, BEIS's 2016 electricity generation costs, and Arup's internal view of CCGT load factors.

Method 1, shown in Figure 1, produces generally lower ASPs than Method 2, with an ASP in the central case of £47.0/MWh. Sensitivity testing of Method 1 gives a range of results between £38.0 /MWh and £54.4/MWh.

Method 2, shown in Figure 2, outturns an ASP of £52.5/MWh. Sensitivities analysed using BEIS low and high commodity price forecast give a range of ASP between £41.4/MWh and £60.2/MWh.

Method 1 may double-count some of the system costs of onshore wind, since the wholesale price is already depressed by intermittent generation on the power system. This effect, combined with the greater subjectivity and volatility of forecast data for Method 1, leads us to the opinion that Method 2 better reflects the intention of a Market Stabilisation mechanism and is more robust in terms of auditability of inputs and observable data points.

Our analysis has not taken account of the headroom potentially required to attract entrants to market and promote competition in order to drive cost reduction through future deployment. Taking account of such an effect would support the optimisation of future cost reduction through effective competition and deployment

Taking account of this analysis and the comments above, Arup believe that an ASP in the region of **£50-£55/MWh (2012 prices)** properly reflects a market stabilisation concept.

2 Background to Market Stabilisation CfDs

In the past, Government has provided support to onshore wind generation in order to encourage deployment, moving it towards maturity and promoting technological development and the emergence of a sustainable supply chain. Onshore wind was previously supported by the Renewables Obligation (RO) and Feed in Tariff policies. These demand-led schemes successfully brought forward 8.5GW of onshore wind in Britain.

As part of Electricity Market Reform, the CfD mechanism was identified as an optimal means by which Government may facilitate a competitive route to market for low carbon generation. The established CfD mechanism could facilitate a Market Stabilisation CfD to continue to deploy established low carbon technologies post-2020. The CfD is not a demand-led regime and Government can limit the strike price paid and budget allocated to deliver the generating capacity required. By using a competitive auction to determine the contract price, the CfD prevents overpayment to generators. Furthermore, the two-way nature of the CfD limits the ability of the generator to collect proceeds over and above the contracted strike price, with any surplus returned ultimately to the consumer. As the first CfD allocation round concluded in 2015, investors have gained experience and confidence in the mechanism.

The Administrative Strike Price (ASP) set for technologies participating in CfD auctions is determined by BEIS using its Dynamic Dispatch Model to assess the capacity developed at different prices. This accounts for the Levelised Cost of Electricity (LCOE) of technologies and competition between projects. For

onshore wind in particular, the ASP takes into consideration the LCOE of onshore wind, cost of capital and risk characteristics of investing in low carbon generation. This reduces over time to account for learning effects, innovation and increased deployment. Outturn strike prices are derived following the CfD competitive 'allocation round' process. The lowest strike price for onshore wind in the February 2015 CfD auction was £79.23/MWh.

The levelised cost of onshore wind has fallen in recent years to around £63/MWh for a mid-range onshore wind project. Arup's recent analysis and review of renewables' costs indicates that the most efficient onshore wind projects, relying on the latest technology, could achieve a LCOE as low as £50/MWh (which would be consistent with a strike price somewhat above that level). These projects are exceptional, and would need to deploy larger, taller turbines at the best wind resource sites. Moreover, such projects may well be subject to very close scrutiny by stakeholders, communities and planning authorities with only those developments having local support proceeding given the current planning legislation.

A Market Stabilisation CfD could provide an appropriate mechanism to bring forward competitively auctioned new generation, including onshore wind and other established technologies. The CfD framework has the capability to drive cost reduction and efficient deployment of new capacity, whilst ensuring a balance of different types of generation using minima/maxima limits.

3 Approach to Method 1 and 2

3.1 Method 1

The adjusted market revenue method seeks to equate the ASP with a potential future market revenue stream adjusted for externalities. The calculation takes into account revenues from:

- Wholesale market – £/MWh wholesale market revenue (including the effect of carbon pricing) available to an onshore wind generator.
- The GB capacity market – revenue received by generators offering firm capacity into the Capacity Market.
- Ancillary services – revenue received by generators from offering ancillary services to National Grid.
- System costs – the intermittency of some forms of renewable generation, including onshore wind, is an important aspect that the System Operator is required to manage. The system costs associated with managing this energy mix therefore need to be considered across the various forms of generation supported by a Market Stabilisation CfD.

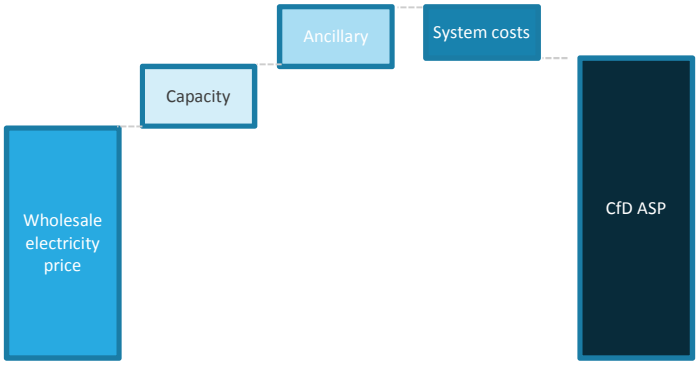

Figure 3: Illustration of Method 1 - wind market revenues with adjustments

3.2 Method 2

The cost based method sets the ASP equal to an adjusted levelised cost of energy of new build CCGT as follows:

- Capital cost – capital expenditure required to build a new CCGT, inclusive of financing costs.
- O&M cost – costs of operating and maintaining the asset.
- Fuel cost – cost of input gas over life of the asset.
- Cost of carbon – carbon costs over the life of the asset.
- System costs - see system costs described in Method 1.

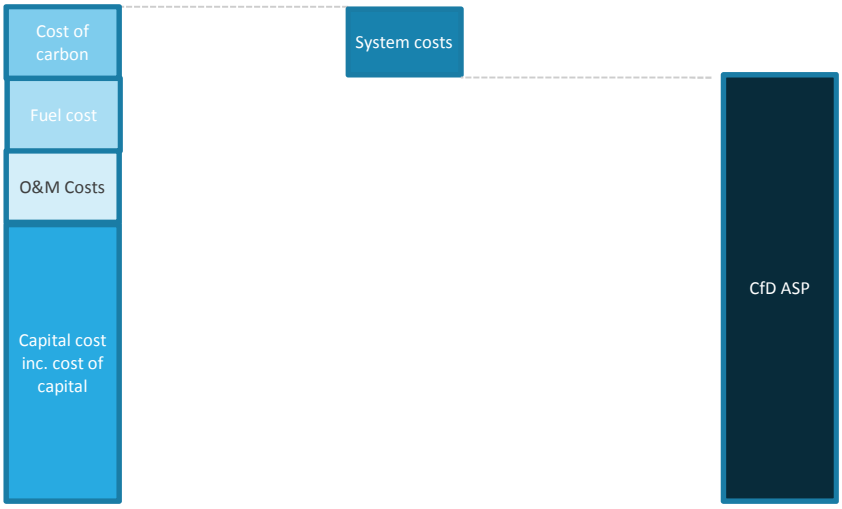

Figure 4: Illustration of Method 2 - New CCGT cost based

4 Assumptions common to both methods

4.1 System Cost

The problem of how to manage the challenge of decarbonising the electricity sector at an affordable price, within the limitations of an electricity infrastructure designed around thermal generation, is currently being faced. There is a need for further investment in the electricity system and there has been discussion as to whether the costs incurred can be apportioned to specific technologies. A question remains over how these costs are apportioned between generating technologies and suppliers.

There has been discussion about whether a Market Stabilisation CfD should take account of the costs that arise due to the characteristics of intermittent generation when compared to the past model of dispatchable, centralised generation. These costs are not fully reflected in the connection or use of system charges of a generator. The CCC describes this as "intermittency cost", for example reflecting that a system with variable renewable capacity will generally need flexible capacity that can operate at peak demand.

System costs attributable to a particular technology will be dependent on the current or forecast generation mix in the market. The higher the proportion of intermittent generation already on the system, the higher the system cost of an additional MW of intermittent capacity. If a charge is imposed on intermittent generation and the system doesn't evolve in the way that the government expects, intermittent generators may be overpaying for their impact on the system.

System costs under this method should be applied across all technologies receiving a Market Stabilisation CfD. Whilst a number of studies have been published in relation to system costs, the methodologies for calculating system costs are not always transparent.

One of the key questions with regards to any approach to quantify a specific system cost for a particular technology is to what extent new projects should be held responsible for the previous decisions made which have led to the existing generation mix. For example, a new wind farm project is not responsible for the wind capacity already on the system or the existing generation mix, therefore there is an argument that it should be treated as though it is the first MW of wind when calculating its system costs. Arup's view is that the Market Stabilisation CfD should calculate system costs at the time of the auction, based on the forecast generation mix at the time of commissioning. Given that the CfD will be awarded 2-3 years prior to commissioning, the system costs would have to be based on a forecast generation mix.

We have considered two approaches to system costs:

1. Take the estimates of future system costs per MWh of wind over the lifetime of the CfD (e.g. 2020 – 2034). This ensures that onshore wind being built has the system costs over its CfD term reflective of the system costs under the forecast generation mix. The shortcoming of this method is that the future mix is unknown and not under the control of a wind

developer looking for a project to commission in 2020.

2. We have also looked at the approach of holding the system integration cost at the estimated cost at the year of commissioning, which is reflective of the assumed generation mix at the time of commissioning but is not influenced by a longer term forecast of the future generation mix. This approach holds the project accountable for its current impact on the system however not its future costs which are beyond its control. This approach could lead to slower wind rollout when the share of intermittent generators is high and before flexibility and storage solutions are widespread.

Arup has conducted a literature review in order to provide an indicative view of the system costs of additional wind capacity. The review has focused on five papers:

a. Nuclear Energy Agency (NEA) and OECD, 2012.
b. NERA and Imperial College published for the CCC, 2015.
c. NERA and Imperial College published for Drax, 2016.
d. Energy Research Partnership, 2015.
e. Imperial College, published for Innogy, RES and Scottish Power Renewables, 2016.

a. The NEA and OECD study calculates system costs based on either a 10% or 30% share of generation by intermittent renewables, which is below the share assumed in 2030 by both the CCC's 50g/kWh and 100g/kWh scenarios. This provides a reasonable mid-point for intermittent renewable's share of generation over the period to 2030.

£/MWh	**CCGT**		**Wind**	
Renewables penetration Level >>	**10%**	**30%**	**10%**	**30%**
Back up costs (adequacy)	-	-	4.05	6.92
Balancing costs	-	-	7.63	14.15
Grid connection	0.56	0.56	3.96	3.96
Grid reinforcement and extension	-	-	2.95	4.52
Total grid-level system costs	0.70	0.90	18.70	29.90
Total external system costs (£/MWh 2012)	0.00	0.00	7.30	13.30

Table 1: Nuclear Energy Agency and OECD estimate of integration costs of CCGT and Wind, published 2012

b. The NERA/Imperial College 2015 and 2016 studies calculate the Whole System Costs relative to nuclear, which has low system integration costs whilst being low carbon. This work provides estimates for a 100g/kWh carbon target.

	Wind	Solar PV	CCS
100 g/kWh scenario	6.2 - 7.6	6.1 - 9.2	(6.4) - (0.5)
50 g/kWh scenario (wind dominated)	12.5 - 15.6	12.1 - 17.1	(7.0) - 4.6
50 g/Wh scenario (solar dominated)	9.5 - 14.3	26.2 - 27.6	(7.5) - (2.8)

Table 2: NERA / Imperial College Whole System costs in 2030 relative to nuclear, published Oct 2015 for The CCC

c. The NERA/Imperial College 2016 work uses a 100g/kWh scenario. This work provides estimates for system integration costs for wind in 2020, 2025 and 2030. It is notable that the system cost falls between 2025 and 2030 as more flexible generation/storage comes onto the system. In our modelling of DECC pricing scenarios we have assumed an installed capacity of 50GW wind by 2030 which is in line with the 50g/kWh scenarios. The NERA/Imperial College 2015 work explores the effect of the 50g/kWh scenarios and it can be seen to increase the system cost in 2030 by over 50% (taking the lower bounds in the wind-dominated scenario).

	2020 (£/MWh)	2025 (£/MWh, 2012)	2030 (£/MWh)	SIC Average 2020 - 2030 (£/MWh)
Onshore Wind	8 – 16	15 – 18	7 – 9	10 - 14
Offshore Wind	8	15	7	10
Solar PV	9	14	12	12
Biomass Conversion	1	-3	(1)	(1)

Table 3: NERA / Imperial College Whole System costs relative to nuclear, published Feb 2016 for Drax

d. The Energy Research Partnership's research into system integration costs provides a view of the sensitivity of the system cost of wind on the amount of wind already installed, as well as the amount of nuclear capacity already on the system. The scenarios have been run for carbon prices of £70/t and £100/t making them difficult to apply to wind built in 2020.

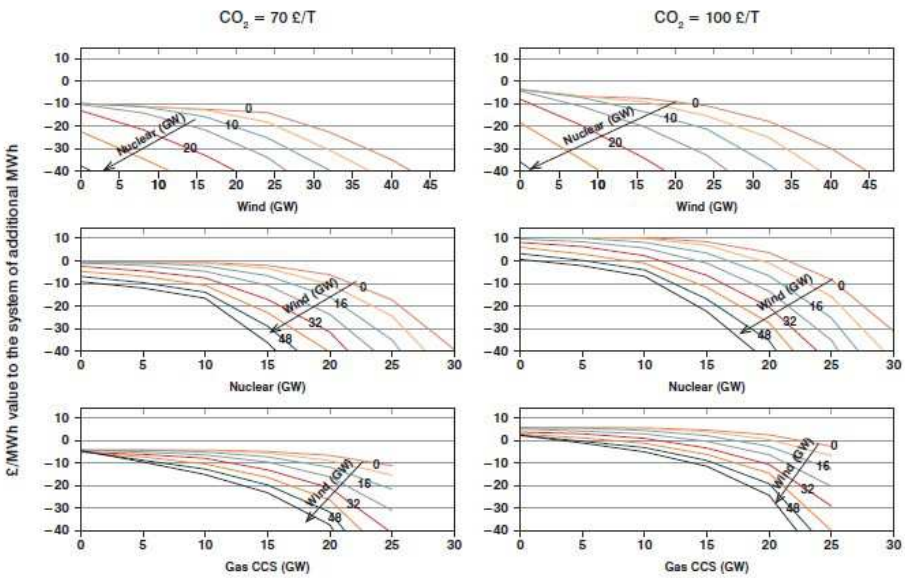

Figure 5: Energy Research Partnership - System cost of generation estimates at differing levels of wind/nuclear and carbon price

e. The Imperial College study for Innogy, RES and Scottish Power Renewables provides system integration costs for a variety of technologies. The study finds that in a "Business as usual" scenario the system integration costs of onshore wind will be £10.2/MWh, whilst if the grid is made more flexible, this could be reduced to £7.6/MWh.

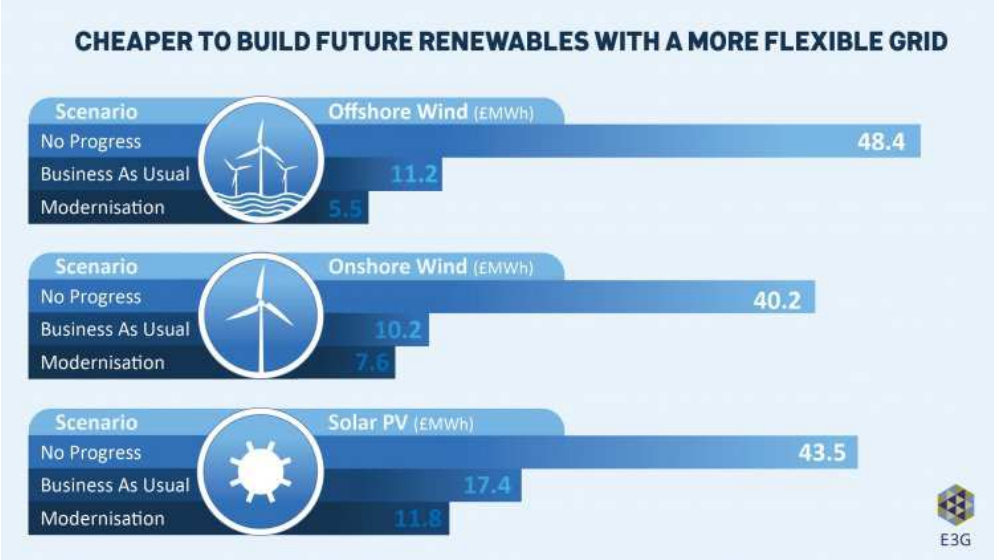

Figure 6: System integration costs of Offshore Wind, Onshore Wind and Solar PV. Source E3G, Plugging the Energy Gap (summary of the Imperial College Report for Innogy, RES and Scottish Power Renewables).

Our review has highlighted the wide range of estimates of system integration costs which have been calculated by different parties. It also demonstrates how the scenarios of generation mix, fuel prices and carbon price have dramatic impacts on the results. The true system costs of an intermittent generator are also dependent on its location and the flexibility it can offer to the grid. A one-size-fits-all approach to the system cost adjustment is administratively the most simple, but other approaches could be taken with a locational aspect.

New renewables projects are investigating the provision of ancillary services that could be offered to support grid stability. By offering additional services, renewables could lower their system cost. However this would vary from project to project, making them difficult to quantify in an ASP calculation. Competitive allocation of CfDs however should drive forward the best projects which are able to offer such services and reduce overall costs

4.1.1 Arup's approach to system costs

To provide estimates of system costs for this analysis, we have concentrated on the NERA/Imperial College and NEA/OECD research which has been undertaken recently and allow the system costs of onshore wind to be assessed in the UK. For both of our proposed approaches to the system cost calculation, we have taken a discounted average of system costs between 2020 and 2034.

For Approach 1, we have applied the following principles:

- From the NEA/OECD study, we have taken the current and forecast level of wind's share of electricity generation and linearly interpolated between 2016 and 2030 based on the values provided by the study. We recognise that the relationship between wind capacity and the system cost of wind is not linear, as shown in the Energy Research Partnership study and accept this is a simplification in our work.
- From the 2016 NERA study based on 100g/CO2, we have taken the three lower bound points provided in the study and linearly interpolated between them, following the approach used by NERA.
- In the 2015 NERA study, fewer data points were provided. We have used the 50g/kWh scenario result as the 2030 figure, and used the upper bounds of the 2016 study for the 2020 and 2025 assumptions. We believe that this will over-estimate the costs in the short term however will provide a view of the upper limit of system costs.

For Approach 2, we have taken the estimated 2020 system costs and held them constant until 2034.

The results suggest a range of discounted system costs between £5.06/MWh and £10.28/MWh. For the purposes of this study we use the figures from the NERA/Imperial 100g/kWh scenario and system cost Approach 2, £5.06/MWh.

	Discounted averages	
	Approach 1	**Approach 2**
NEA/OECD estimate	10.28	6.52
NERA/Imperial estimate (100g/kWh)	6.41	5.06
NERA/Imperial estimate (50g/kWh)	9.50	9.68

Table 4: Discounted system costs of wind between 2019 and 2030, discounted at 7.8%Method 1 Specific Assumptions

4.2 Wholesale Market and Capacity Market

For Method 1 we have assessed three main scenarios. These scenarios were chosen as they best reflect Government's view of future price development.

- Central – Uses BEIS's Central scenario prices for electricity and Arup's assessments of capacity market prices, ancillary services revenues and system costs.
- High – Uses BEIS's High scenario prices for electricity and Arup's assessments of capacity market prices, ancillary services revenues and system costs.

- Low – Uses BEIS's Low scenario prices for electricity and Arup's assessments of capacity market prices, ancillary services revenues and system costs.

4.3 Cash flow Modelling Assumptions

The scenarios use the 2016 BEIS LCOE discount rate assumption of 7.8%. We have kept this consistent between the scenarios. Across all scenarios, the Market Stabilisation ASP is calculated over a 15 year duration (equivalent to the CfD contract duration a new low carbon generator may receive) for a new onshore wind generator in 2020.

4.4 Day ahead market prices

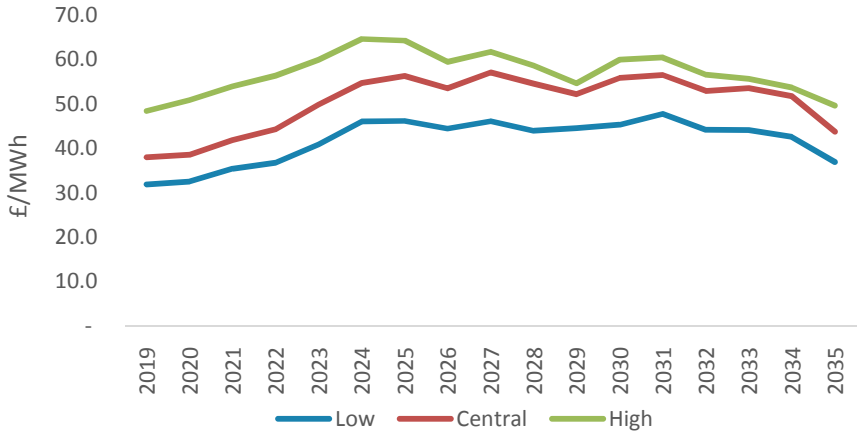

Figure 7: Wholesale market prices 2019 – 2035

4.5 Capacity market prices

Capacity market prices are observed to increase from a low of £18.0/kW for delivery in 2019/2020 to a peak in 2022, as new declining capacity margins increase capacity prices to a suitable level to allow for new OCGT and CCGT to be built. 3GW of capacity is observed to clear the auction in 2022 (1 GW OCGT and 2 GW of CCGT), while 1.4 GW and 0.4GW of capacity clears in the 2024 and 2025 auctions respectively.

We have reduced the capacity market payment included in the ASP build up to account for onshore wind's lower contribution to peak generation.

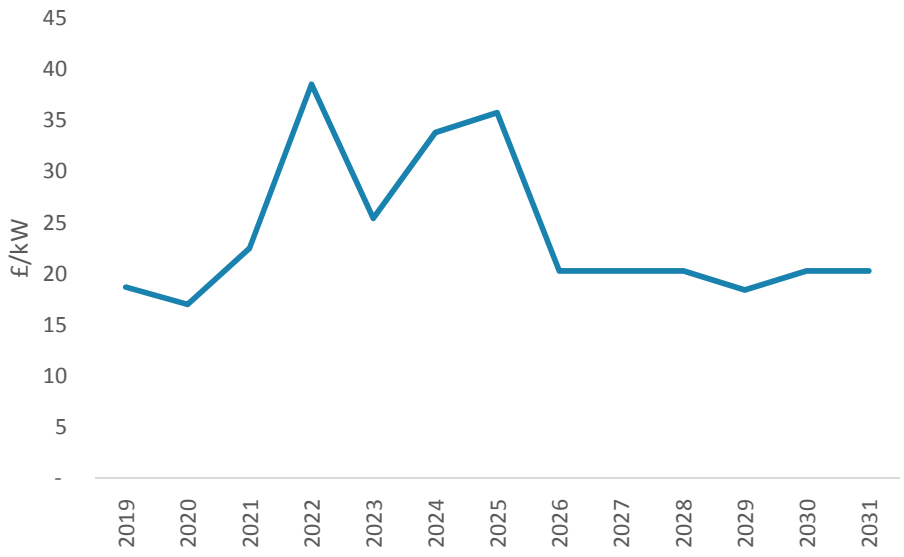

Figure 8: Modelled capacity market prices for delivery years 2019 – 2035

4.6 Ancillary service revenues

Ancillary service revenues (excluding balancing mechanism) make up a relatively small part of potential revenues. We include ancillary service payments to CCGTs in the Method 1 ASP calculation in order to match the revenues of onshore wind to those for a CCGT, however we note that an ASP including only wholesale, balancing and capacity market payments is also an option.

4.6.1 Frequency Response

Frequency response is an ancillary service provided by generators in the UK. Generators are paid a holding fee, made on the basis of a unit's ability to provide the service and an utilisation payment (response energy payment) which is set to reflect market prices.

The holding payment revenue for primary, secondary and high frequency response was calculated from average historical holding price and volume for high efficiency CCGT's in 2015 (Staythorpe, Pembroke and West Burton B).

5 Method 2 Specific Assumptions

5.1 Gas Price

The gas price used in the analysis is taken from the 2016 BEIS Energy and Emissions Projections. The Central gas price rises from 27.3p/th in 2016 to 58.4p/th in 2030 where it holds flat. The High scenario rises from 34.8p/th in 2016 to 67.8p/th in 2030. The Low scenario begins at 21.6p/th in 2016, rising to 35.8p/th by 2030.

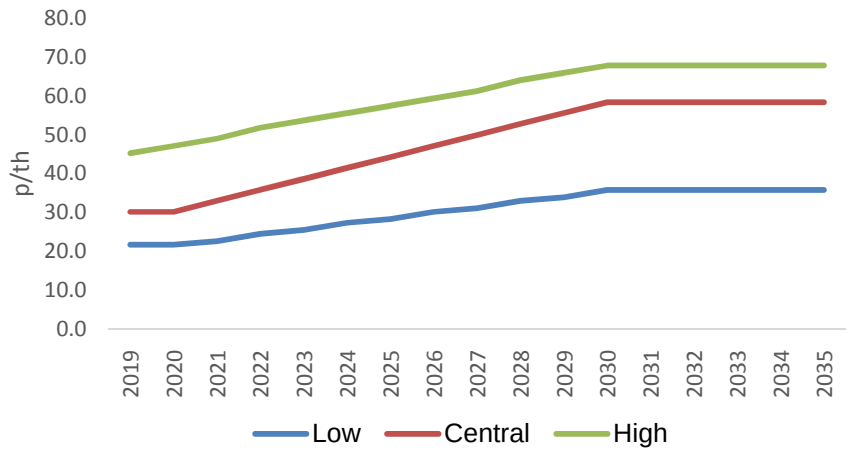

Figure 9: BEIS Energy and Emissions Gas price assumptions

5.2 Carbon Price

The gas price used in the analysis is taken from the 2016 BEIS Energy and Emissions Projections. All scenarios use the same carbon price, which rises from £20.9/tCO2 in 2016 to 22.2/tCO2 in 2026 and to £95.2/tCO2 in 2035. The BEIS carbon price has the GB Carbon Price Floor accounted for in the forecast.

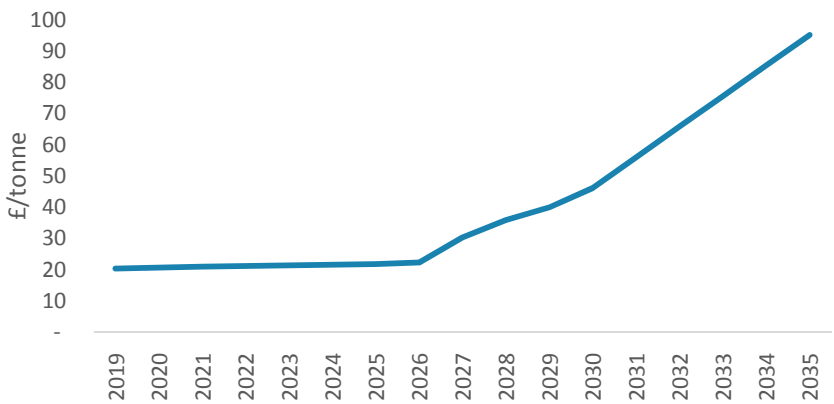

Figure 10: BEIS Energy and Emissions Carbon price assumptions

5.3 Load Factor

In all scenarios, we have used an assumption of 83% for the load factor of a CCGT. This is based on Arup's in-house modelling of a new CCGT's load factor. The 2016 BEIS LCOE analysis assumes a load factor of 93% which we believe to be very high even for an efficient CCGT. We have kept this assumption consistent between the scenarios although we note that the actual load factor may change depending on the capacity mix in each scenario. In the case of a CCGT, it takes a large swing in the load factor to create a significant change in the LCOE. The load factor only impacts the capital cost and fixed cost elements of the LCOE, which are relatively minor elements for a CCGT in comparison to its variable costs.

5.4 Discount Rate

The scenarios used the BEIS 2016 LCOE report discount rate assumption of 7.8%. We have kept this consistent between the scenarios. Similarly to the load factor assumption, small changes in the discount rate do not have a great impact on the final LCOE. The discount rate has the greatest impact on the capital cost element, through the cost of finance, and the fixed cost. Since both the generation and variable costs are discounted in the LCOE calculation, the discount rate has very little impact.

5.5 CCGT Efficiency

In all scenarios, we have used an efficiency of 54%, as used in the BEIS 2016 LCOE report. Since the efficiency has a direct impact on the fuel used and carbon emitted, the impact of a change in efficiency is significant.

5.6 Pre-development and Construction Period

In order to allow for the easiest comparison between the scenarios, the pre-development and construction periods have been fixed at a total of three years.

The results of the analysis using the BEIS fossil fuel price assumptions are highly dependent on the operational start date of the asset, largely due to the high carbon price at the end of the operational period.

5.7 Fixed O&M costs

The scenarios use a fixed O&M cost of £11,619/MW/year based on the BEIS 2016 LCOE report.

5.8 Variable O&M costs

For all scenarios we have used the variable O&M cost of £2.86/MWh as in the BEIS 2016 LCOE report.

5.9 Capital costs

The scenarios assume a capital cost of £476/kW for a new CCGT built in 2020, based on the BEIS 2016 LCOE report.

6 Method 1 results

In this section we set out the results of the scenario analysis conducted for Method 1. For Method 1, the Central, High and Low scenarios were considered.

6.1 Central Scenario

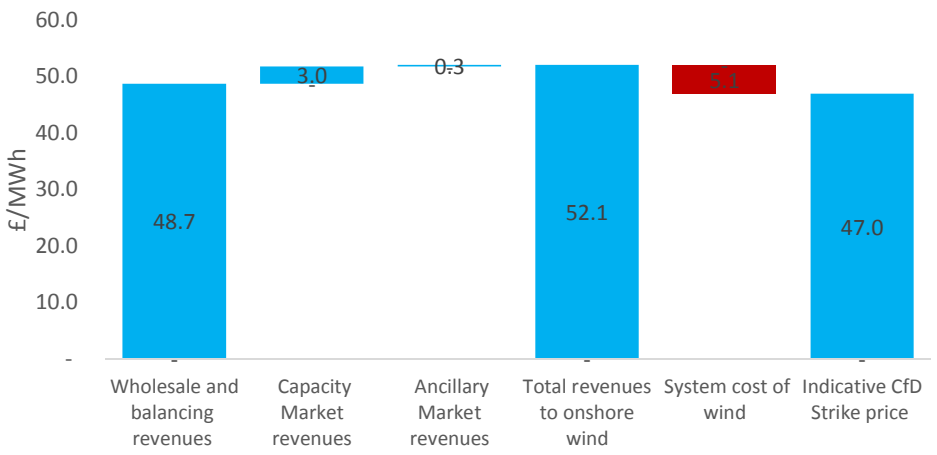

Figure 11: Method 1 Administrative Strike Price build-up in the Central scenario

The Central scenario assumes commissioning of a windfarm in 2020 and uses:

- BEIS 2016 Central assumption for the wholesale electricity price
- Arup's assessment of future capacity market prices, potential balancing and ancillary services revenues
- Arup's literature review of system integration costs for wind

The Central scenario results in a Market Stabilisation ASP of £47.0/MWh. The analysis highlights that the wholesale market revenues make up a significant component of the ASP under this method.

We note that the inclusion of capacity market revenues on top of the system cost of wind may over-compensate onshore wind for the back-up power it offers (since it should already be accounted for in the system cost). The NERA/Imperial analysis does not offer any breakdown of the system costs thus we are unable to properly adjust for this effect.

6.2 High Scenario

The High scenario assumes commissioning of a windfarm in 2020 and uses:

- BEIS 2016 High assumption for the wholesale electricity price
- Arup's assessment of future capacity market prices, potential balancing and ancillary services revenues
- Arup's literature review of system integration costs for wind

Using the High scenario prices provides an indicative Market Stabilisation ASP to be £54.4/ MWh.

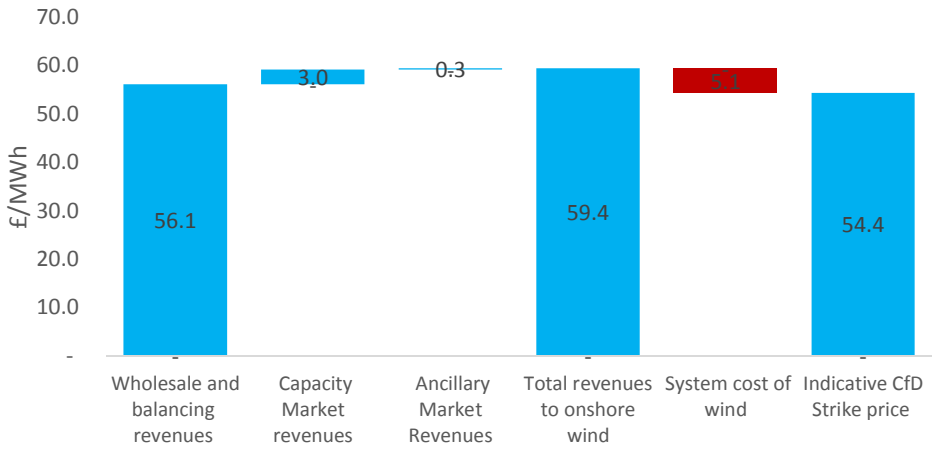

Figure 12: Method 1 Administrative Strike Price build-up in the High scenario

6.3 Low scenario

The Low scenario assumes commissioning of a windfarm in 2020 and uses:

- BEIS 2016 Low assumption for the wholesale electricity price
- Arup's assessment of future capacity market prices, potential balancing and ancillary services revenues
- Arup's literature review of system integration costs for wind

Using the Low scenario prices provides an indicative Market Stabilisation ASP to be £38.0/ MWh.

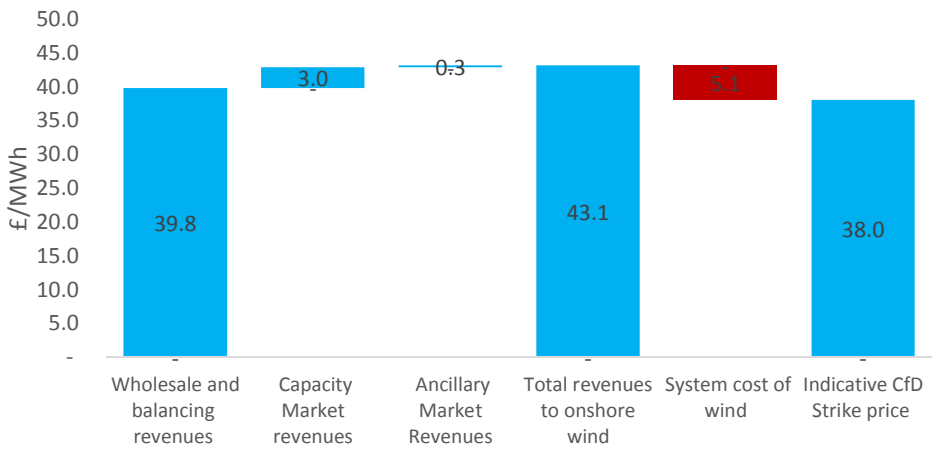

Figure 13: Method 1 Administrative Strike Price build-up in the Low scenario

Our analysis suggests that at £38/MWh the Method 1 low scenario could not facilitate new build generation of any type within the UK.

7 Method 2 Results

In this section we set out the results of the scenario analysis conducted for Method 2. For Method 2, three scenarios, the Central, High and Low were considered.

7.1 Central scenario

The Central scenario assumes commissioning of a CCGT in 2020 and uses:

- BEIS LCOE 2016 assumptions for Capital, Variable and Fixed O&M costs.
- BEIS 2016 Central assumptions for Carbon and Gas costs
- Arup's literature review of system integration costs for wind

The Central scenario produces a levelised cost for a new CCGT of £57.6/MWh. Subtracting the system integration cost produces an indicative CfD ASP of £52.5/MWh.

The majority of the levelised cost of a CCGT is comprised of the fuel and carbon costs, meaning that the use of this method will be sensitive to the prices used.

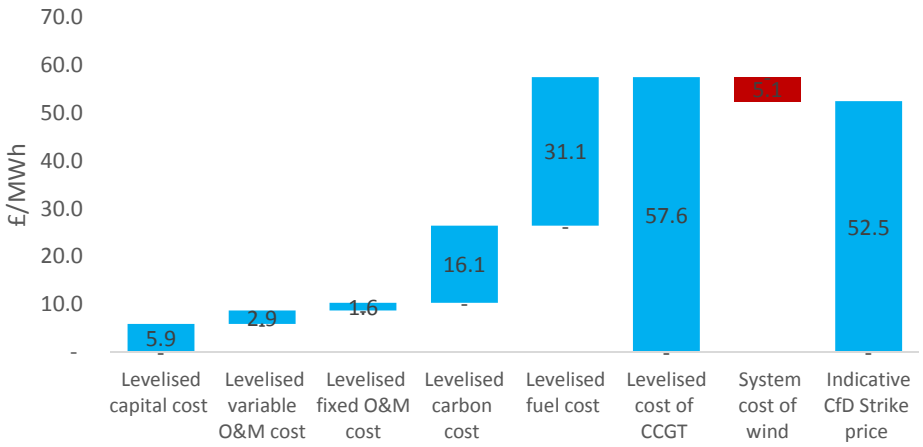

Figure 14: Method 2 Administrative Strike Price in the Central scenario

7.2 High scenario

The High scenario assumes commissioning of a CCGT in 2020 and uses:

- BEIS LCOE 2016 assumptions for Capital, Variable and Fixed O&M costs.
- BEIS 2016 High assumptions for carbon and gas costs
- Arup's literature review of system integration costs for wind

The increased gas price assumption drives the levelised cost up. In the High scenario, an LCOE of £65.3/MWh is produced. After the system cost adjustment this yields an indicative CfD ASP of £60.2/MWh

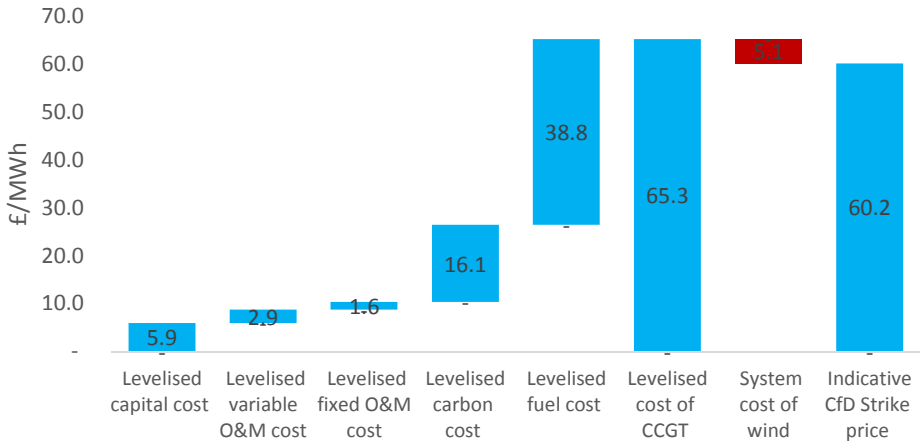

Figure 15: Method 2 Administrative Strike Price in the High scenario

7.3 Low Scenario

The Low scenario assumes commissioning of a CCGT in 2020 and uses:

- BEIS LCOE 2016 assumptions for capital, variable and fixed O&M costs

- BEIS 2016 Low assumptions for carbon and gas costs
- Arup's literature review of system integration costs for wind

The commodity prices in the Low scenario reduce the carbon and fuel costs by 24%. The LCOE in this scenario is £46.5/MWh, with the indicative CFD ASP being £41.4/MWh.

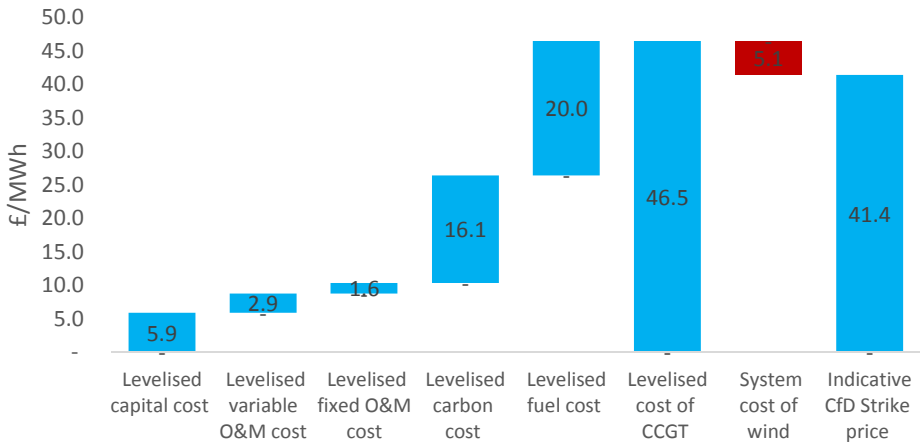

Figure 16: Method 2 Administrative Strike Price in the Low scenario

Our analysis suggests that at £41.1/MWh under the Method 2 low scenario it would be extremely challenging to deliver new build gas generation in the UK.

8 Moving from LCOE to ASP

Under its previous administrative price calculation methodologies, the Government adjusted the levelised costs of the relevant technologies in order to account for a variety of external factors. These include:

- Technology specific factors – capital, operating and financing costs. For example, transmission losses will be paid by the generator but are not included in the LCOE methodology.
- Market conditions – the extent to which generators receive a discount to the wholesale price through the terms of their PPA (or the cost of balancing which is not normally included in LCOE but is covered by the ASP)
- Policy considerations – contract design, targeted technology mix and meeting decarbonisation ambitions.

Under the Market Stabilisation methodologies, such adjustments should not be required since the benchmark being used is no longer the LCOE of onshore wind.

9 Comments and Conclusions

As we have shown in the preceding analysis, the CfD price cap indicated by Method 2 is highly dependent on the gas and carbon prices used. This effect is clearly due to these assumptions being a direct input into the LCOE calculation. Nonetheless, the result of Method 1 is also dependent to some extent on the gas and carbon prices used since these are a key driver of the wholesale market price (along with the capacity of wind on the system). Indeed, because Method 1 depends very heavily on a forecast of wholesale market prices (which is necessarily subjective) it follows that it is likely to be subject to greater subjectivity and volatility.

Method 1 may double-count some of the system costs of onshore wind, since the wholesale price is already depressed by intermittent generation on the power system. This effect (combined with the greater subjectivity and volatility of the data set for Method 1) leads us to an opinion that Method 2 better reflects the intention of a Market Stabilisation mechanism.

Our analysis has not taken account of the headroom potentially required to attract entrants to market and promote competition in order to drive cost reduction through future deployment. Taking account of such an effect would support the optimisation of future cost reduction through effective competition and deployment.

We consider that an ASP cap in the region of **£50-£55/MWh** reflects an appropriate range for a Market Stabilisation CfD mechanism.

9.1 Areas for further consideration

9.1.1 Integrated modelling

Our approach to Method 1 has included integrated wholesale market, capacity market and balancing market revenues. It does not account for differences in system costs between the scenarios offered. A similar effect should be seen in Method 2 – differences in gas and carbon prices will lead to differences in system costs.

An integrated approach to modelling system costs and other inputs for both methodologies could be a more robust way of producing Market Stabilisation CfD prices. In this analysis, we have used a simple, constant system cost for wind; however, outturn system costs will be dependent on fuel and carbon prices and the mix of generation on the system. The inputs to the ASP all need to be modelled concurrently in order to provide a consistent result.

This effect should help to provide some stability to the ASP; the greater the gas or carbon price, the greater the wholesale market price and LCOE of gas, and the greater the system cost of wind.

9.1.2 Agreement and calculation of further externalities

Agreement will need to be reached on any further externalities to be considered in the Market Stabilisation calculation. These externalities will then need to be calculated.

9.1.3 Cap progression over time

Our analysis has provided a view of the likely level of Market Stabilisation CfD based on the two approaches for projects being commissioned in 2020. Further work would be required to see how the level of the cap may develop over time.

In particular, Method 1 modelling should further investigate the impact of wind penetration on the level of the cap against the forecast learning rates for wind.

9.1.4 Onshore wind supply curve

It is important to gain an understanding of the supply curve of projects to enable BEIS to forecast expected onshore wind deployment going into each CfD round. This will provide further evidence to support the methodology and cap level. Onshore wind still has an important part to play in reaching renewables targets and setting a cap too low will jeopardise the development of the industry.

10 Appendix: 2015 BEIS scenario results

10.1 Method 1

In this section we set out the results of Method 1 using BEIS's 2015 price assumption.

- BEIS 2015 Central assumption for the wholesale electricity price
- Arup's assessment of future capacity market prices, potential balancing and ancillary services revenues
- Arup's literature review of system integration costs for wind

The 2015 Central scenario estimates the Market Stabilisation ASP to be £52.4/MWh. BEIS's 2015 price assumption was higher than the 2016 assumption. This results in a higher stabilisation price.

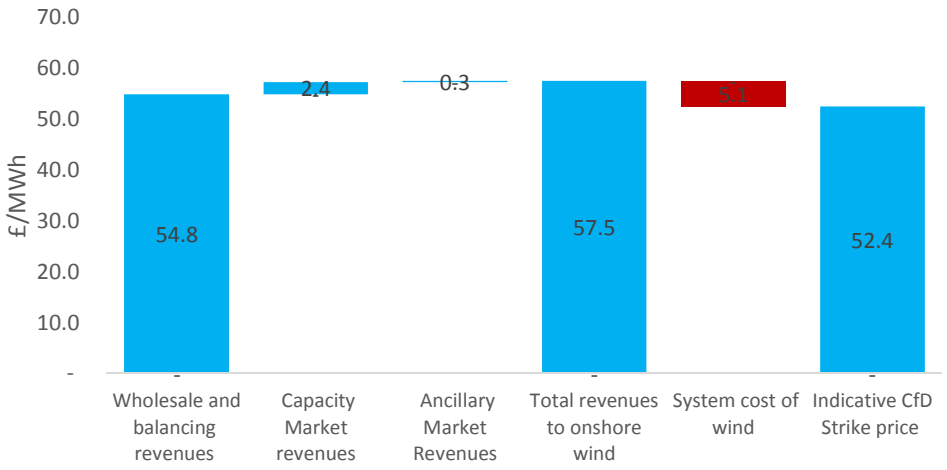

Figure 17: Method 1 Administrative Strike Price build-up in the 2015 Central scenario

10.2 Method 2

The Central Scenario assumes commissioning of a CCGT in 2020 and uses:

- BEIS LCOE 2016 assumptions for Capital, Variable and Fixed O&M costs.
- DECC (BEIS) 2015 Central assumptions for Carbon and Gas costs
- Arup's literature review of system integration costs for wind

The 2015 Central scenario produces a levelised cost for a new CCGT of £64.0/MWh. Subtracting the system integration cost produces an indicative Market Stabilisation ASP of £58.9/MWh.

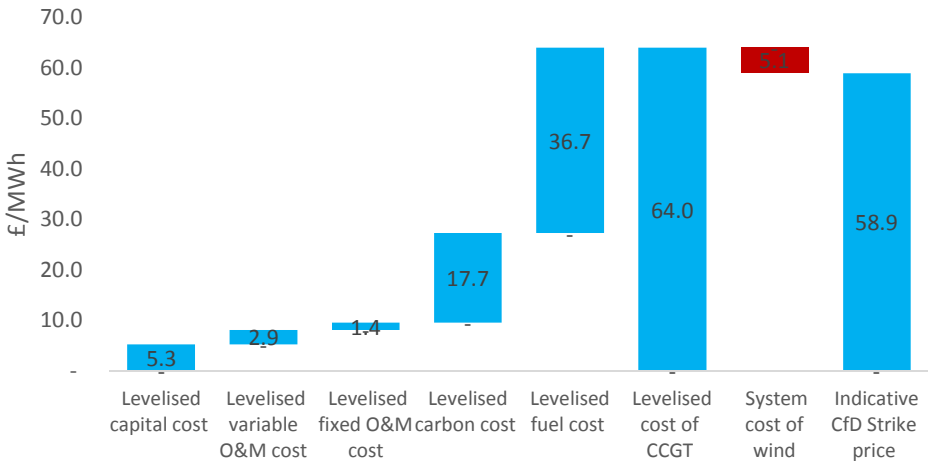

Figure 18: Method 2 Administrative Strike Price in the DECC Central scenario

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