Electricity Market Reform Consultation
Response from ConocoPhillips (U.K.) Ltd

ConocoPhillips (U.K.) Ltd welcomes the opportunity to respond to the Electricity Market Reform (EMR) Consultation.

ConocoPhillips is an international energy company operating in over 30 countries. Our European Power Development group based in the UK is therefore competing for internal investment funds on an international basis. Our interest in the UK power market is in projects related to our core business assets. This interest has resulted in the construction of the largest CHP in the UK adjacent to our Humber Oil Refinery. The Immingham CHP project provides steam to Total's Lindsey and ConocoPhillips's Humber Oil Refineries which together represent 25% of UK refining capacity. The first phase of the Immingham CHP project was 730 MW which was commissioned in 2004. A second phase was commissioned in 2009, which increased the plant capacity to 1220 MW.

ConocoPhillips also has section 36 consent for an 800 MW CHP facility at Seal Sands in Teesside adjacent to the ConocoPhillips-operated Teesside Oil Terminal. We are currently looking at the investment case for this project and, were this investment to proceed; it would supply reliable low cost steam to the Terminal and a number of third party facilities in the area. ConocoPhillips' UK power development group is also analysing both biomass and peaking enhancements to our Immingham site.

ConocoPhillips has been active in the UK power market since 2003. The vast majority of power produced at our 1.2GW Immingham CHP plant is sold into the wholesale market. Due to low market liquidity there are days when our trades have represented approximately 50% of the month ahead market and 30% of the day ahead market

As a Downstream operator in the extremely competitive refining sector, ConocoPhillips has invested in making the Humber Refinery one of the top 10% most energy efficient European refineries. This investment has included the Immingham CHP plant, which was the best technology available to lower the carbon footprint of our Humber Oil Refinery.

ConocoPhillips has been a significant investor in the United Kingdom oil and gas industry since September 1964.

Introduction

ConocoPhillips understands the Government's ambition to reduce UK carbon emissions and the consequent targets for renewable generation, resulting in a requirement for £200 billion of investment in energy infrastructure. However, we do not believe the current combination of preferred options will deliver the necessary outcomes to;

- Ensure sufficient investment in new generation capacity
- Provide adequate market signals to create the amount of flexible generation which is able to respond to the intermittency of a, largely wind driven, renewable generation portfolio and an inflexible nuclear fleet.
- Ensure a robust and liquid power market that will provide a reliable power price signal and encourage new entrants into the UK power market.

In particular, ConocoPhillips believes that;

- An already illiquid power market could be further damaged by the proposed reforms.
- The role of efficient gas plant and, in particular Combined Heat & Power (CHP) technology, in meeting both the carbon emissions and security of supply agenda at a relatively low cost is not recognised.
- The potential impact of the UK Electricity Market Reform proposals and, in particular, the CPS consultation on the generation sector in general and the CHP sector in particular has not been estimated. Charging CHPs Carbon Price Support (CPS) in the fuel used to generate heat means that CHP projects will be disadvantaged versus the separate production of power and heat.

We believe that the problem which the Electricity Market Reform (EMR) is trying to solve has not been clearly or fully defined and the repercussions of an increased nuclear and wind-driven power generation system not fully understood. As a result our response finds that the solutions suggested are inadequate.

- Carbon Price Support does not provide a certain revenue benefit for low carbon generators.
- A Contract for Difference/Feed in Tariff, or similar, may undermine the market on which it relies.
- Targeted Capacity Mechanism will not provide a sufficient amount of the right type of flexibility for the system.
- Emissions Performance Standards appear similar to existing measures including the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED) and is therefore unnecessary duplication.

ConocoPhillips, along with the six other independent (non vertically integrated) power generators in the informal Independent Generators Group, has commissioned some modeling work from the independent power consultancy group, Oxera, to inform our views (see Appendices I & II). This analysis has been undertaken within a constrained and challenged time period, dealing with a complex set of issues that will require further investigation as outlined within the Oxera report, a full version of which has been submitted by the Independent Generators Group in response to the EMR consultation. In particular more in-depth analysis is required on any potential capacity mechanism and the analysis has been based on 20GW of wind by 2020. This could arguably have been a much higher figure and, as a result, the current analysis may understate the flexibility requirements of the UK.

One further area for concern is the increased layering of costs to industry, additional to those being borne by European competitors. At the levels suggested in the consultation, by 2030 UK industry might be paying carbon costs in electricity prices several times greater than the rest of Europe, when CPS and CRC are taken together. In many industries this will be sufficient to produce a significant impetus for imports. It is essential that the total impact of climate change measures on industry costs is clearly assessed.

It will be noted in our response that we are of the view that natural gas-fired power generation is the lowest cost low-carbon form of power generation and that it should not be put at risk by the reforms. We see the advantages of natural gas being as follows:

Gas is naturally the cleanest burning fossil fuel.

- It produces 55% less CO2 emissions than coal when burned for power generation
- It also produces relatively little nitrogen oxide, sulphur dioxide or particulates

The reliability and flexibility of natural gas also make it an essential backup to intermittent low-carbon sources of energy such as wind and solar.

Natural gas has a higher conversion efficiency, which means it loses less energy than other fossil fuels when producing electricity or heat.

Natural gas is competitively priced and requires no subsidies for future supplies.

The technology for using natural gas is advanced, rapidly deployable and affordable.

- A gas-fired power plant takes as little as three years to build

The availability of natural gas for consumers is ensured through existing and extensive transport and distribution infrastructure – the use and cost of which is controlled through regulation.

Natural gas is abundant and remains a highly important indigenous resource in Europe.

Globally, there are enough proven reserves to meet more than 60 years of demand at today's consumption rates.

Worldwide potential from 'unconventional' sources of natural gas, such as shale and coal bed methane, could extend current production by a century or more.

Gas production within the European Economic Area is expected to remain at high levels for decades, with the possibility of unconventional gas offsetting declining production in some Member States in the longer term.

In the US, technological advances have led to a tripling of shale gas production in four years – transforming US indigenous supply and ensuring self-sufficiency for more than a century.

- With shale gas meeting US needs, there is more conventional gas available to diversify supplies for Europe
- LNG that would otherwise have been needed in the US is now free to go wherever the market draws it

Security of supply is increased by access to diverse sources of gas – which is increasingly a global commodity:

- Europe is within economic range of large and diverse gas sources
- Security of supply can be further enhanced by market interconnection, storage capacity and route flexibility – all achievable through better infrastructure

All of which means that:

- Natural gas offers Europe the greatest potential for cost-effective reductions in greenhouse gas emissions – using existing technology to help meet EU 2020 goals.

- Natural gas is ideal for power generation and heat supply.

- Natural gas is more than a ‘transition fuel’ since it meets each of the EU’s triple objectives: reduced emissions, security of supply and affordability.

Any questions arising as a result of this response should be addressed to Maureen McCaffrey at maureen.mccaffrey@conocophillips.com

CONSULTATION QUESTIONS

The Government's objective for the consultation process is to develop the evidence base on the options for reforming the electricity market. Therefore, respondents to this consultation are asked to provide evidence and supporting information to backup any opinions expressed in their response.

Current Market Arrangements

1. Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

We understand that incentives may be needed in the short term to stimulate low-carbon investment but we do not agree that the incentive mechanism proposed by Government is the right one. We are unclear as to exactly what the Government's assessment is, as a number of seemingly contradictory statements are made in the Executive Summary. Below we quote the Executive Summary with our comments or questions below.

"Even as we improve efficiency, demand for electricity may need to double by 2050…..due to increased heating and transport demands".
If heat and transport are to be electrified and demand doubled, the base case should reflect such an increase rather than showing flat demand.

"*The Climate Change Committee has recently proposed that the power sector should be close to zero carbon by 2030*".
There appears to be some conflict between the Climate Change Committee view and DECC's view. If this quote reflects DECC's view, it is not reflected in Redpoint's analysis.

"*Gas fired generation…. will continue to play an important role in the electricity sector providing vital flexibility."*
This seems to directly conflict with the statement above unless it is assumed all gas plant has CCS fitted by 2030. It also implies CCS plant will emit zero carbon and is flexible in order to manage demand and supply swings (see our response to Question 2).

"*The scope for demand side flexibility will significantly increase as electric vehicles become more common*."
We agree that with the demand growth in power consumption that the result of growth in these areas will mean that increasing amounts of demand flexibility are available. However, as discussed above, the basis of Redpoint's analysis does not include this demand growth.

The contention is that

"*Without reform, the existing market will not deliver the scale of long-term investment, at the pace we need, in particular in renewables, new nuclear and CCS, nor will it give consumers the best deal*."
We believe this statement should go on to say 'nor will it support the on-going and future investments in flexibility necessary in order to complement the non price responsive nature of much of the new low carbon technologies'. This aspect of future generation needs is not addressed by the proposed reforms and is perhaps evidenced by the recent announcements in relation to plant closures, investment delays and cancellations.

2. Do you agree with the Government's assessment of the future risks to the UK's security of electricity supplies?

No, we believe the Government has underestimated the importance of a liquid traded market for power in the UK. In fact, this EMR has preceded the outcome of OFGEM's liquidity review. DECC has seen liquidity as an issue to be managed by OFGEM once the EMR package has been decided, rather than as a necessary platform in order for the EMR reforms to work and an issue that may be inherently affected by those reforms.

> *".. worth noting in the context of security of supply is the fact that, over a 90 day period during the heart of the winter, actual output of wind generation connected to the electricity grid only averaged 21% of its nominal capacity and on 83 of the 90 days it did not exceed 50%, with one period of seven days during which it never rose above 10%. The maximum achieved on any one day was 67% and the minimum was less than 1%. While the proposed offshore wind projects mentioned above are likely to perform better because it is windier offshore, these figures illustrate vividly the need for other means of reliable and flexible generation in order to maintain electricity supplies. It should be noted, though, that maintaining large numbers of wind turbines in maritime conditions will unquestionably be more difficult than onshore." (ref p.17 of Oil & Gas UK's Economic Report, 2010).*

We do not believe that Government has analysed the 'Flexibility Gap' that will be created from the combination of intermittent wind power and base load nuclear plant. We have worked with Oxera to further analyse this gap (see Appendix I).

We believe existing and new gas plant can provide a significant proportion of the flexible generation at a relatively low cost. A number of studies have been carried out recently concerning the costs of various forms of generation. For example, the study by Redpoint for the Energy Networks Association states in its conclusions (on page 54):

> *"Given the level of uncertainty that exists regarding all of these issues, there appears to be significant value in retaining the option for a "high gas" future. This is particularly relevant given that our modelling indicates that pathways with ongoing gas use could yield cost savings relative to those with higher levels of electrification, particularly under scenarios with low growth in commodity prices and / or slower rates of technology learning. While all of our scenarios anticipate a significant increase in the use of electricity by 2050, a balance between fuel sources may help to reduce the risk of over-reliance on particular technologies."*

DECC themselves commissioned Mott McDonald to study UK Electricity Generation costs in 2010. Their conclusions (on page 65) found:

> *"CCGTs running on gas have both a lower capex and lower levelised cost than the main baseload generation alternatives with a LGC around £80/MWh in our base case. Gas prices have to exceed the DECC high case for CCGT to look unattractive, and coal prices would have to be much lower than DECC is projecting."*

Moreover, the European Gas Advocacy Forum have just released a report that states

> *"The potential for reducing emission reduction costs [at EU level] by using gas in the energy mix is sizable in comparison with the pathway described in the ECF [European Climate Foundation] Roadmap 2050 '60% Renewable Energy Sources (RES) scenario'.*

For the period 2010-2030, total investment costs in the power sector could be €450-550 bn lower, leading to an improvement in overall power-system costs of ~€500 bn."

As currently drafted the EMR would not appear to allow for the development of new CCGT plant as it would not receive a CfD/FiT nor be able to gain a Targeted Capacity Payment (TCP). As shown in Appendix I Fig 3 it would also not be able to achieve the highest prices (peak prices) in the market as the STOR and TCP recipients would skim off these higher payments. The result means that CCGT's are unable to meet there fixed costs, see Appendix I Fig 6. The failure to capture these prices would lead to less development and more need for TCM plant (this feedback loop continues until eventually there are no plants available to provide flexibility but excluded from the FiT or TCM incentives).

We believe failure to analyse the Flexibility Gap and the costs that will result from this failure could fundamentally undermine the UK power market. The result may be that relatively inefficient 'peaking plants' are used much more than is intended and ultimately emergency derogations for existing coal plant may be necessary in order to ensure sufficient supply. Thus the measure could actually lead to an increase in carbon emissions. The load factor on CCGT can be expected to drop to as low as 20%-40% in the mid 2020's. It is clear that the projected load factor for fossil fuel plant will also vary considerably from year to year, not just as a result of demand but also as a result of wind variability.

Given this combination of factors, it is not possible to see how any investor could develop a gas-fired power project that would make an acceptable economic return, this conclusion is supported by the RedPoint analysis (figure 19).

"Earlier investment in nuclear under Fixed Payments and Contracts for Difference, coupled with the assumption that the 2020 renewable targets can be met, results in no further CCGT investment after 2012."

It is also difficult to see how the UK can have a reliable power supply without such investments. Even with the more limited projections of the 'Flexibility Gap' contained in the consultation (page 23, clause 17), it is acknowledged new thermal plant is needed.

We are concerned that in a low carbon future, generation needs will be met by large scale and intermittent off-shore wind, inflexible nuclear plant that to date has a track of very long delays and budget overrun, and as yet unproven large scale CCS. In the case of CCS, it is also assumed that plant will be retrofitted with this technology in a very short time period.

The proposed future UK market structure, in which fossil fuel power plants equipped with CCS provide load following support to baseload nuclear power plants and variable wind supplies, presents significant technical challenges and cannot be economically justified. Existing CO_2 storage projects -- Sleipner, Snovhit, Weyburn and In Salah -- all operate at relatively constant rates with little variability across the entire value chain of capture, transport and storage. Post combustion solvent-based capture plants can be designed with some degree of flexibility to follow loads, albeit with an economic penalty due to efficiency losses and additional technical complexity. Oxy-combustion and integrated gasification combined cycle (IGCC) plants with CCS will face greater technical challenges operating at variable loads due to the integrated nature of the capture processes within the overall power production scheme. The ability of transportation systems to deal with variable flow will be constrained by the necessity of maintaining the carbon dioxide in a supercritical state.

Storage studies, to date, have assumed a constant flow of CO_2 from source to injection point and a supply of supercritical CO_2 sufficient to maintain injectivity and maximise storage efficiency. Variable flows will significantly affect the uptime of the storage operations and dramatically increase performance risk, as time and care must be taken to ramp up injection. Injection rates that change too quickly will risk damage to the wellbores and to the storage formation. Variable flows increase the risk of intrusion of formation water into the wellbore which could cause corrosion in the well and damage to the reservoir, increasing the risk of leakage and reducing the security and effectiveness of storage. For these reasons, fossil fuel plants equipped with CCS will likely be deemed "must run" plants with limited flexibility, while un-captured simple cycle and combined cycle natural gas plants combined with energy storage and demand management systems, will be required to handle load following in a low carbon electricity market.

In the case of the balancing requirement, it is demand side response and power storage that are relied upon in the consultation. Whilst we think more of these will be needed we do not believe they can develop to meet the very large flexible requirements in the foreseeable future identified in Appendix I fig 2. Demand side response is only likely to happen at scale if transportation is electrified. As demand is flat in the base model there appears limited scope for demand side response here. Storage via pumped storage, battery technology and compressed air may take place but it will involve energy losses of around 20% and hence more demand for power in the first place. Again, this additional power demand is not reflected in the base economics.

Overall we believe the strategy is predicated on slow demand growth and successful implementation of three new technologies with no contingency plan. In addition there is no proper assessment of how much flexibility and of what type will be needed to ensure UK consumers can meet their energy demands.

Options for Decarbonisation

Carbon Price Support

This is the subject of a separate HM Treasury / HMRC consultation. Readers of this consultation with specific comments on the carbon price support mechanism should cover these in a separate submission to the HM Treasury / HMRC consultation, which can be found at http://www.hm- treasury.gov.uk/consult_index.htm

We refer you to our response to the Carbon Price Support Consultation. Attached in Appendix III

Feed-in Tariffs

3. Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?

No, the cost to society calculation isolates the cost that will be paid out under the FiT from other effects. For example, if a CfD makes the large vertically integrated players, in particular, indifferent to the health of the traded power market (as the price for their renewable output is guaranteed) it will disincentivise them from ensuring that the traded power market is liquid and deep. Similarly the cost of administration and implementation of a more complex CfD is not reflected in these calculations.

Government contends that a CfD FiT is more favourable than a Premium FiT because of the £3.3Bn NPV net benefit of a CfD Mechanism, as per the 'Summary of Analysis and Evidence' for the differing packages under consideration, contained in the Impact Assessment. This delta is driven by the additional capital costs required under the Premium FiT package (that Redpoint have estimated)

> *"if the financing costs in the premium payment package were applied to the same decarbonisation and technology profile achieved in the CfD or fixed payment packages"*

We would contend that the premium payment package meets the criteria set and therefore it is not necessary to 'force' the Premium FiT profile to mirror that of the CfD FiT. The Premium FiT also has the following benefits over the CfD payment package that is not assessed in the analysis:

- Reduced potential to impact market liquidity negatively
- Easier to implement
- Simpler for Government to administer
- Reduced risk of an investment hiatus

The increased risk of an investment hiatus under a CfD mechanism is not calculated in the modeling with the assumption being that investors react perfectly. As already highlighted their have been a number of recent announcements of plant closures and projects being delayed or cancelled. Government should recognise that an investment hiatus is a likely reaction to a fundamental change in policy that the CfD mechanism creates and is likely to result in a 'decarbonisation and technology profile' similar to a Premium FiT thereby removing some of the benefit created as a result of modeling assumptions. Furthermore, our contention is that a mechanism that damages liquidity is likely to raise the costs associated with that mechanism which is again not included with the analysis of the two policies.

What is clear is that the modeling of any combination of policy measures or individual elements is highly driven by the underlying fundamental environmental assumptions and the way modeling outputs are interpreted. We would urge caution in Government forming opinions on the future of the electricity market based upon modelling results that may or may not materalise over time.

4. Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?

No, we think a FiT with CfD will undermine the traded power markets. Hedging output forward will be made very difficult. Of the options presented, we believe a Premium FiT is less damaging to liquidity. This would be very simple to administer (output * FiT). It would also be easy to band, should different technologies or vintages require a different price to reflect their carbon saving. Generators would still be free to operate in the market and, most importantly, the benefits of a competitive market would be maintained. CfD FiTs are not risk free in terms of value (as outlined in the Consultation Document) as the CfD is predicated on there being a market price against which to settle the CfD. Using Government projections, low carbon generation will be able to satisfy all UK demand occasionally from 2018 and more than 50% of the time by 2025. If this is the case, it is unclear how the traded market would work at all and what would happen in the case of negative prices. Low carbon generators would still be incentivised to generate. The cost to Government of a CfD in a negative price environment is not calculated.

We would find awarding CfDs via auction process particularly ineffective in maximising capital availability and believe it would increase administration and implementation costs. Government rather than developers would ultimately have the build decision. Either, developers would need to develop projects on the off chance of winning an auction, hence spending developments funds without the ability to make the decisions to go ahead with their projects themselves, or developers would bid on the basis of undeveloped projects which may or may not come to fruition as developers may have underestimated cost, grid access etc. Winning an auction with an undeveloped project is like obtaining a strike price against which a developer may choose, or not, to develop a project at a future date. The UK has already experienced this with the NFFO auctions where only 25% of the winning bids went ahead.

Alternatively, with a Premium FiT developers are in charge of their own decisions. The Premium FiT would form a floor to revenue with remaining revenue received from the market. If there is concern about the costs of a Premium FiT in a high wholesale price environment, the FiT could contain a clause stating that, when market prices reach X, the FiT is reduced by a given percentage.

We also believe it would be relatively simple to grandfather the value of ROC into a Premium FiT mechanism and do away with the Renewable Obligation, thus further simplifying the regulatory landscape. Additionally, incentives for CHP could be transposed into a Premium FiT mechanism, set at the appropriate level to reflect their carbon saving. Finally, Premium FiTs are very simple for investors to understand and value with little hidden cost.

A further concern with the FiT with CfD approach comes from reported earnings volatility. Although the CfD would result in a more stable price per MWh on delivery, it is a financial derivative. The value of this contract will fluctuate over time with the forward market price. Although any change in the value of the contract will be offset by the changing value of output, it is only the change in value of the contract which will be reportable for future forecast volumes. This potentially significant swing, which is not present in a Premium FiT approach, could act as a disincentive to investment as well as a barrier to entry for smaller firms unable to accept this earnings volatility.

In addition to the reported earnings volatility the potential for significant mark-to-market exposure under a CfD FiT will increase credit risk, which is particularly challenging for small independent generation as well as providing a significant barrier to new entrants that the Government is keen to encourage.

5. What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under the CfD model?

It is not appropriate to transfer all risk from generator to Government. It is not appropriate for Government to take on technology risk or development risk for example. These are risks best met by commercial companies who can use their development experience to best estimate project economics including development time, technology risk etc. However to the extent Government has objectives that are not reflected in the commodity prices it may choose to correct these market ‘errors’ by creating a secondary market to reflect the cost or by guaranteeing some incremental level of return to projects that assist them in reaching those ambitions. The Government should however consider the unintended consequences of introducing these ‘distorting’ characteristics into the market. Should the Government go ahead with the its ‘Preferred Package’ under the EMR the proportion of the market not receiving the substantial amount of its revenue via Government schemes (The Squeezed Middle) will be very small and in time of low demand may not exist at all from as early as 2018. As a result the Squeezed Middle can no longer hope to develop projects or capacity on a normal financial basis. Our proposed resolution to this problem is laid out in Appendix II.

6. What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

See answer to question 5.

We are unclear as to what is meant by operational decisions but we will split them into three for the purpose of this response:

- Investment decisions
- Maintenance and medium term operating conditions
- Dispatch decisions.

Investment decisions – apart from the normal investment decisions such as IRR, availability of capital and perception of risk, power plant developers will consider also operational items such as as how much flexibility and redundancy to build into a plant design. Potential investors will also consider location and how this might affect both cost and revenue, including ability to dispatch and load factors.

Maintenance and medium term operating conditions. – power plant managers will look at the effects of running configurations on revenues and costs. These factors will impact their willingness to turn a plant on and off and ramp up and down. They will also try to coordinate maintenance with periods of projected low revenue. The way in which a plant is operated may require different staffing levels including the ability to trade on a 24 hour basis and to change operating mode during the nights. Operating may be constrained by conditions contained in the Long Term Service Agreements or manufacturers' guarantees. The necessity to keep spares or spend additional capital to maintain or increase flexibility will all be considered in the light of the ability to obtain higher revenues.

Dispatch decisions – The basic precept that as long as the marginal revenue exceeds the marginal cost then a plant will dispatch is a reasonable starting point. There are, however, a number of complicating factors which should be applied to this basic concept. Variable costs will include fuel, environmental permits, transmission and transportation, losses, water use etc, associated with each marginal unit of production. As well as all of the constraints noted above a plant may need to take into account the effects of changing operation on when it might next need to carry out maintenance. As plant increases its flexibility it will bring forward its next planned maintenance. Planned maintenance is based on 'fuel hours fired' with an upward adjustment made for times when the plant is ramping up or down. Unplanned outages will also increase if a plant is turning on and off or ramping up and down a lot. We note in Redpoint's analysis, the de-rated capacity of CCGT is based on historic numbers which have been extrapolated forward. This is incorrect as CCGT will be required to be a lot more flexible as windpower increases in the UK. Both planned and unplanned outages would increase as a result. Plants will take into account their view of future prices in any operating decision. For example, they may decide to hold back some generation if they believe imbalance prices may be penal, in order to ensure a safety net. Other issues affecting operational decisions will be the minimum stable generation, weather (more can be produced by a gas-fired facility when it is cold) and efficiency or the plant at varying output levels. Plants will also consider prices and their view of future prices in any decision to turn down, maintain equipment on warm or hot standby, provision of ancillary services etc.

7. Do you agree with the Government's assessment of the impact of the different models of FiTs on the cost of capital for low-carbon generators?

The consultation recognises in Box 5 of the document that when comparing hurdle rates:

> *"The greater the certainty of revenues that can be offered to investors, the lower the project cost of capital…. In practice, a Premium FIT is far less complex than the RO (as discussed below in chapter 2 and below in the section on a low-carbon obligation), and takes away additional uncertainties over revenue."*

Therefore the impact on hurdle rates under a Premium FiT given this simplifying assumption is understated when compared to the baseline in relation to reductions in hurdle rate.

Additionally given that the CfD FiT mechanism relies on a liquid market to set a reference price and, as we contend a CfD FiT has far greater potential to damage liquidity in comparison to a Premium FiT, it could be argued that the hurdle rate reductions for a CfD FiT are overstated. As Government recognise in the Impact Assessment (page 71):

> *"92. For renewables for example, it is not necessarily the case that moving from the RO to a fixed FIT or CfD amounts to a move from no price risk insulation to full insulation, which is what the Redpoint analysis assumes. The implication of this is that the cost of capital reduction in reality may be lower than that demonstrated by the modelling."*

Furthermore Government recognises:

> *"94. In reality, the cost of capital effect of price certainty will be difficult to distinguish as other risks associated with low-carbon generation (such as planning, construction, availability and performance) may dominate investors' perceptions of project risk, and hence costs of capital."*

8. What impact do you think the different models of FiTs will have on the availability of finance for low-carbon electricity generation investments from both new investors and the existing investor base?

We believe a CfD FiT will not maximise future investment because of the complexity and the uncertain level of interaction with the power market. If investors cannot foresee what will happen to the power market against which the CfD is to be settled, then there will be no confidence in the measure. If investors do not believe the interaction between the CfD mechanism and the market is credible in the long term, they will not have the confidence to invest. There is also a potential that earnings volatility (as a result of accounting for the value of the CFD (see question 4) will negatively impact the availability of finance.

We believe one mechanism, a Premium FiT, could be banded so as to incorporate grandfathered ROC revenues, reflect different vintages and the environmental benefits of differing technologies so as to better meet the objectives of investors.

9. What impact do you think the different models of FiTs will have on different types of generators (e.g. vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would the different models impact on contract negotiations/relationships with electricity suppliers?

Independent generators are the most vulnerable to a poorly functioning market as they must use or sell their output, normally at a discounted rate, to the large supply companies. Ensuring that market liquidity is unharmed by the measures is vital to ensuring that all players in the market are encouraged to invest in the power sector and that new entrants are able to compete. As we highlight in response to question 10, we believe that a Premium FiT is the best method of protecting at the very least the current levels of market liquidity

10. How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

Liquidity
The power market is already recognised as being short of liquidity, and that positive steps need to be taken to encourage an improvement in this situation. Greater liquidity in the wholesale market is extremely important for the effective operation of the overall power market under a FiT with CFD model. While wind can intermittently provide energy, it by definition can never provide firm capacity to the grid. Thus, for every unit of potential wind that is put on the grid, essentially an additional amount of flexible capacity is required to create one full unit of both energy and capacity. Low-carbon generation alone will not provide security of supply as investment in flexible generation is also required, in part by independent generators who rely on a liquid wholesale market. However, the FiT with CFD model is likely to damage, rather than boost, liquidity as a substantial amount of generation will be insensitive to market price.

Low-carbon generators would be indifferent to the market price because the CFD guarantees revenues. As such, there would be no incentive to trade at a realistic level that even returned marginal costs to other generators.

Under the FiT with CFD model, volumes in the prompt market would become highly volatile, with large numbers of sellers during windy days but few participants at other times. If renewable generators are guaranteed income set against a particular reference price, they are unlikely to trade in periods other than the one that sets the reference price. In the case of unpredictable intermittent wind generation, it is likely that the prompt market will be favoured from a risk perspective. As such forward trading will see little interest.

This would create a vicious cycle, with dramatic price moves on windy days that cause the price to be trading away from power fundamentals, further reducing the amount of speculative traders providing liquidity. From our own knowledge and experience within the ERCOT (Electricity Reliability Council of Texas) market, similar in size to the UK market, the introduction of Intermittent Wind to a particular trading area has destroyed liquidity in that particular area, as participants are unwilling to engage in markets with such a high level of uncertainty.

The CFD with FIT model will create unrealistically low market prices at periods of high wind. The extreme volatility caused by this price swing and the intermittent nature of wind will reduce the number of players willing to take positions in the market and trade around those positions, and as such will reduce liquidity further. The resulting extremely low prices will increase the cost of the subsidy to the Government. The reduction in liquidity combined with below-fundamental market prices will mean that the UK power market is unattractive for investment by independent generators.

Reference Price
The reference price should not mandate the use of a particular commercial exchange, particularly where the costs of using that exchange are higher than other pre-existing routes to markets. Any reference price for a CFD will be complex to administer and understand, particularly for small independent low-carbon generators who will have to pay a premium in order to manage their trading exposure. In determining the reference price, the following should be considered:

- Due to the intermittency of wind generation the reference price should be set for periods close to delivery. It would be inappropriate to use a longer term contract such as month ahead.
- Setting the reference price at too granular a level will increase the complexity of administration. For that reason, a half-hourly reference price should not be used.
- A day ahead reference price is probably the most appropriate time period for an index as it is close to delivery but not too granular. However, power is priced on a half-hour basis and wind generation is not baseload. A wind generator will therefore sometimes be generating in periods priced higher than the day ahead index, and at other times lower than the index. This market price structure means that a generator is not guaranteed revenue for any particular MWh. While it is likely that, over the long term, the generator will be indifferent to this it would be more difficult to explain to financiers than a Premium FIT.

11. Should the FIT be paid on availability or output?

The FIT should be paid on output. We cannot see any positive effects of payment on availability as opposed to output. Paying a FiT on availability could encourage poor commercial decision making, such as the poor siting of wind turbines. If generators were paid on availability, it would be absolutely necessary to ensure that they could not also receive any constraint payments. It would also be necessary to reduce any payment based on availability by any variable costs not incurred as a result of not operating. This would include water and reprocessing costs in the case of nuclear plant, fuel in the case of bio-mass plants, and losses and transmission costs for all generators. This becomes very complicated as these costs would need to be determined. If payments were not reduced by this amount it would lead to the perverse situation where plant was paid more for not operating than for operating.

Emissions Performance Standards

12. Do you agree with the Government's assessment of the impact of an emission performance standard on the decarbonisation of the electricity sector and on security of supply risk?

We do not support the introduction of yet further unilateral UK carbon emission regulations. Emissions Performance Standards appear similar to existing measures including the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED) and is therefore unnecessary duplication. We also believe the Carbon Reduction Commitment (CRC) should be abolished as it is now just another user tax and causes double taxation and competitive distortions as well as unnecessary red tape. Other carbon related measures include: the EU ETS, Renewable Heat Incentive, Climate Change Levy and now the proposed Carbon Price Support. We also understand that there will be a CCS Levy.

13. Which option do you consider most appropriate for the level of the EPS? What considerations should the Government take into account in designing derogations for projects forming part of the UK or EU demonstration programme?

Please see answers to Questions 12, 15 and 16.

14. Do you agree that the EPS should be aimed at new plant, and 'grandfathered' at the point of consent? How should the Government determine the economic life of a power station for the purposes of grandfathering?

Please see answers to Questions 12, 15 and 16.

15. Do you agree that the EPS should be extended to cover existing plant in the event they undergo significant life extensions or upgrades? How could the Government implement such an approach in practice?

If introduced, the measure should be clear and certain. Any uncertainty here will lead investors to stand back from the market.

16. Do you agree with the proposed review of the EPS, incorporated into the progress reports required under the Energy Act 2010?

We do not believe it is necessary to have the measure. If introduced it must take account of co-firing, biomass and CHP production.

17. How should biomass be treated for the purposes of meeting the EPS? What additional considerations should the Government take into account?

Biomass should be zero rated consistent with treatment under the EU ETS where it is considered carbon neutral. Inclusion of biomass under the EPS would deter investment in carbon abatement on existing plant forcing early closure, and it could deter future investment in dedicated biomass projects due to regulatory uncertainty. If an EPS were to be implemented, upgrades to existing plant to facilitate advanced co-firing should not render such plant to be subject to the EPS.

18. Do you agree the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls?

Such provision already exists for IPPC permits and would be necessary in the event of a security of supply issue.

Options for Market Efficiency and Security of Supply

19. Do you agree with our assessment of the pros and cons of introducing a capacity mechanism?

We believe a capacity mechanism is required in order for the 'Flexibility Gap' to be filled, as shown in Appendix I, Fig 2. It is clear that in order for the system to be able to meet demand net of wind, as evidenced in Appendix I, Figs. 1 & 4, that an increasing amount of flexible plant will be required to meet the 'Flexibility Gap'. Due to time constraints the analysis has been predicated on total capacity as opposed to de-rated fossil fuel capacity, hence in practice the required 'Flexibility Gap' would be even larger than that shown in the analysis. This is particularly the case as planned and unplanned outages for flexible plant are likely to increase as a result of the increased operational strain placed on these facilities.

The uncertainty over the functionality of the market and the low level of load factors that can be anticipated by fossil fuel generators will not allow for the construction of new fossil fuel plant or, in some cases, the continued operation of existing plants. As Government has recognised, it is a very large challenge to raise the estimated £110bn capital investment required in UK power infrastructure. If funds need to be raised from banks, those lenders will focus on Debt Service Coverage Ratios (DSCR) in a downside case. This will mean high renewable growth, with high wind load factors in any given year. This would result in a 20% load factor for a CCGT in 2025. Any developer currently aiming to build a CCGT would be looking at a 2015/16 start. It is difficult to see how any project could proceed with the load factors anticipated during the 2020s if there were no capacity payments available to this type of plant.

Government analysis shows that the cost of a market wide capacity mechanism would be relatively small at 1%. This cost seems small compared to the potential benefits from ensuring security of supply via flexible plant that enables low carbon generation growth to be achieved.

20. Do you agree with the Government's preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?

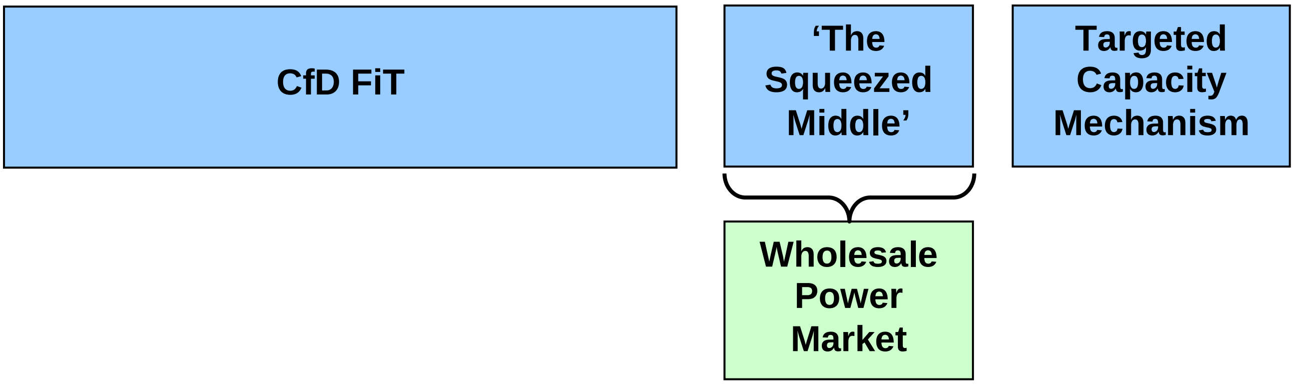
Yes - a capacity mechanism is required. However, we believe a Targeted Capacity Mechanism (TCM) will be inadequate in bringing on the required amount of the right type of flexible plant. As shown in Appendix I fig 6, the impact of market distortions as a result of the TCM means that in 2020 existing CCGT would be unable to meets its fixed costs even under 'perfect' market conditions (perfect foresight, efficient dispatch and no costs of operational flexibility), undermining the market and required investment case. Developers and operators of flexible fossil fuel plant that are not part of the TCM can now expect to have load factors eroded as a result of the incentives provided to low variable cost wind and nuclear. They will also be unable to obtain peak prices for providing flexibility, as the highest prices are now received by plant under the TCM. The remaining plant, the 'squeezed middle', is unlikely to be economically viable in these circumstances. Failure to invest in the 'squeezed middle' will therefore result in underinvestment and a greater need for more, perhaps less efficient plant, to be included in the TCM.

The ultimate result would be a market that is either in receipt of FiT or TCM payments. This would appear to equate to a market controlled totally by a system operator, equivalent to option 5 under Project Discovery, which DECC rejected as leading to too much Government interference.

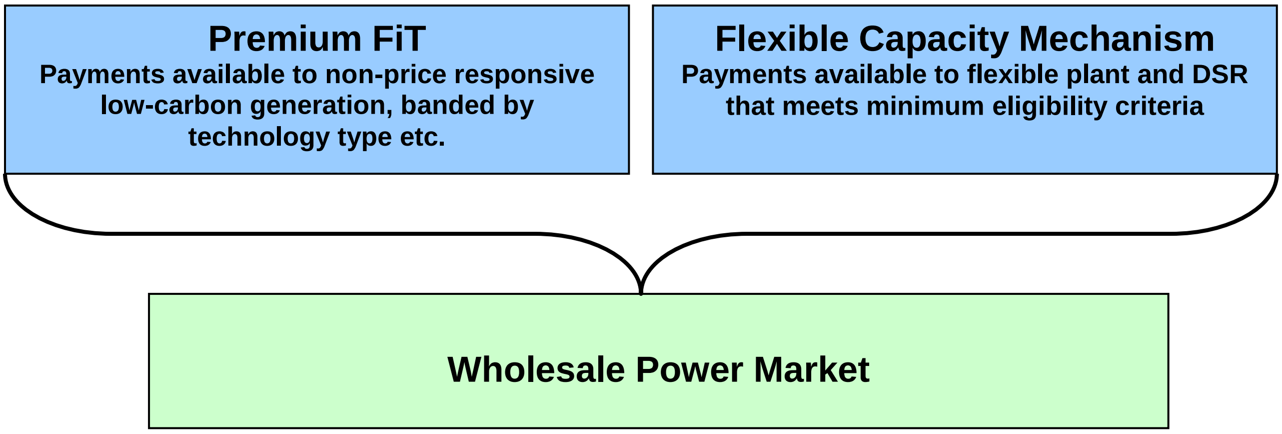
21. What do you think the impacts of introducing a targeted capacity mechanism will be on prices in the wholesale electricity market?

The combination of a CfD FiT plus TCM would leave a very small 'squeezed middle' amount of generation that is reliant on a thinly traded power market and not on incentives as it main revenue driver, as shown on next page.

Government’s Preferred Option



ConocoPhillips’ Preferred Option



It should be noted that, in the ConocoPhillips’ preferred model, a plant could be in more than one category e.g. a CHP may be in receipt of the appropriate level of Premium FiT for the low carbon non-price responsive minimum stable generation element consistent with its steam supply obligations, but the remainder of the plant maybe highly flexible and in receipt of payments under the flexible capacity mechanism. A nuclear plant may also be in receipt of a flexible generation payment for any element of its capacity that can meets the eligibility criteria.

Under the current proposed CFD FiT and TCM model, there would be dwindling generation left to operate effectively in the wholesale market over time. Using Government forecasts from as soon as 2018, on low demand days low carbon generation may be at the margin. From 2025, according to Redpoint’s analysis, fossil fuel will no longer be at the margin more than 50% of the time. The competitive market is so distorted by the FiT and TCM that it would no longer operate effectively. Peak prices will be removed from the market making it more difficult to keep existing plant or to invest in new flexible plant that does not meet the criteria laid out in the capacity mechanism. The effects are significant showing that by 2020 CCGT’s are unable to meet there fixed costs, please see Appendix I fig 6. The effect will undermine the market thus increasing the need for more TCM plant etc so the feedback loop will continue until there is no market remaining.

The TCM is not designed to meet the full flexibility requirement of the market. A broader instrument is needed. See Appendix II. The TCM will not lead to sufficient investment in the right type of flexible plant and the result will be that the market will be squeezed out of existence. Low capital Open Cycle Gas Turbine (OCGT) type projects will be built under the TCM but will have to run at much higher load factors than anticipated because they will have to fill the Flexibility Gap. The new plant will be costly as well as poorly suited to meet all of the flexibility requirements. The cost to the UK will be large in terms of unnecessary investment in the wrong type of plant. Small, low capital cost OCGT will have to operate on a regular basis and would have higher levels of emissions than a large CCGT or a large CHP plant. In the end, the dirty older plants (largely coal) that were due to close may have to be given some derogation in order to provide security of supply. Thus the net effect could not only be money poorly spent but a negative effect on emissions.

22. Do you agree with Government's preference for a the design of a capacity mechanism:

No, we believe a market wide mechanism (excluding those in receipt of a FIT) is required. An outline proposal is contained in Appendix II.

□ a central body holding the responsibility;

Yes, we do believe a central body should have responsibility.

□ volume based, not price based; and

We believe that an auction mechanism will be ineffective and will not provide value for money in the long run. Any mechanism introduced should be based on the amount of flexibility that is required in order to facilitate good security of supply, taking into account the growth in intermittent wind generation and inflexible nuclear capacity. The mechanism should allow for payment to all generation meeting the qualifying conditions but should exclude those plants, or the specific portion of plants, that are in receipt of a CfD/FiT. Any additional revenue over and above that provided by the capacity mechanism should come from the traded power market. A properly functioning market should reflect a higher value for flexible plant than for less flexible. It is the incremental value that can be obtained from the market that will drive the optimal design for flexible plant.

□ a targeted mechanism, rather than market-wide.

It essential that any new capacity mechanism allows payment to all plant that meet the minimum flexibility standard. Demand side or storage projects should also be able to get a capacity payment. When analysing the TCM versus the market wide mechanism, we note that it was assumed that non-flexible or demand responsive renewable plant would also receive a market wide payment. We do not believe this is a reasonable assumption, as these facilities would be funded on the basis of a CfD/FiT. If this assumption is not made, the costs become much more comparable.

23. What do you think the impact of introducing a capacity mechanism would be on incentives to invest in demand-side response, storage, interconnection and energy efficiency? Will the preferred package of options allow these technologies to play more of a role?

We believe the type of market-wide capacity mechanism outlined in Appendix II in combination with a robust and liquid power market could support both demand side response and storage projects.

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:

□ Last-resort dispatch; or

□ Economic dispatch.

Please see Appendix II

25. Do you think there should be a locational element to capacity pricing?

This question cannot be answered without greater context as to the package of mechanism and capacity mechanism design.

Analysis of Packages

26. Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or Premium), emission performance standard, peak capacity tender)? Why?

All of the packages proposed by Government fail to meet the biggest barrier to new entry and do not resolve the key factor in the lack of a forward investment signal, namely liquidity. Lack of liquidity is not addressed in the consultation with the Government handing off responsibility to a body that is currently under review, OFGEM. To date OFGEM have not been able to resolve the liquidity problem and this EMR also pre-empts the publication of its liquidity review findings. Rather than the EMR being seen as an opportunity to help resolve the current liquidity problems, it may worsen them. It is questionable whether OFGEM will be able to resolve the fundamental liquidity problem in the wholesale electricity market, concurrent with the EMR, with the result that the Government objectives of decarbonisation, security of supply and affordability will be endangered.

ConocoPhillips (COP) believes the following actions could be taken in order to improve market liquidity:

- Self supply regulation should be imposed on the large Licensed Supply Companies in order to help market liquidity. They should be required to trade a percentage of their power through the markets rather than direct transfer across their vertically integrated businesses.
- An arms-length transfer price mechanism, based on market prices should be imposed on the large vertically integrated players so as to disincentivise profit being taken from one side of the business (supply or generation) to subsidise the other. This will lower barriers to entry for new independent supply companies and independent generators, as well as encouraging market activity. Currently the large vertically integrated players are able to take profits in generation or supply businesses. This presents a risk to independent generators or suppliers who may become insolvent in a year when profits for integrated participants are taken from the other side.
- Dispatch for low carbon (including CHP) power generation should have priority dispatch over other forms of generation, and in the case of CHP should never be constrained below the minimum level of stable generation that is appropriate to maintain its steam supply.

In relation to the individual elements of the preferred packages laid out by Government we offer the following comments.

Carbon Price Support (as per COP's CPS consultation response submitted on 11th February 2011)

- CHP is disadvantaged versus separate generation of power and heat, under the CPS and if introduced it should apply to electricity only not heat
- CPS leads to a new layer of costs and complexity on industry with complex multiple mechanisms and regulations imposing differing charges for carbon.
- There are very large windfall gains to existing low carbon generators, in particular nuclear generation operators.

- CPS will result in significant market distortion across Europe as imported power will not incur the additional costs and will therefore be advantaged.
- CPS undermines the EU ETS; COP is against unilateral UK cost increases which do not affect the rest of Europe.
- If introduced CPS should be notional until 2018 at the earliest.
- If introduced the Target Price needs to be established at least 3 years forward.

Premium FiT versus CfD FiT

- CfD FiT is more likely to damage liquidity in the market
- CfD FiT is more complex to administer and understand
- Given liquidity issues, it is likely to be difficult to find a liquid price to settle CfD against
- As such, a Premium FiT is preferred as it is simple and can be easily banded to reflect differing costs and benefits and is less likely to damage liquidity. A Premium FiT:
    - Should be applied to all low carbon, non price responsive, generation including CHP at a level appropriate to their relative carbon saving.
    - Should apply to output not capacity.
    - The recipient should remain exposed to market prices to ensure it is incentivised to be available when demand is high.
    - Could be set at a level approximately equivalent to Renewable Obligation Certificate reducing administration without creating investment uncertainty.

Capacity Mechanism

- We believe the proposal for this area is less well developed than others. We believe a market wide capacity mechanism, covering all 'firm' generation capacity and demand side management, except those in receipt of ROC/CfD, FiT and that meets the required flexibility standard is required. An outline proposal is contained in Appendix II

Emissions Performance Standard

- Further unilateral UK carbon emission regulations is not required

27. What are your views on the alternative package that Government has described?

We would agree with Government that, on its own, CPS is unable to provide stable long-term investment signals for all plant and that a Fixed FiT presents the highest level of threat to market liquidity issues, thereby increasing the challenge of Government objectives being met.

We believe a Premium FiT combined with a capacity payment based on the Flexibility Gap identified (as a result of the growing proportion of inflexible and non-price responsive plant) would be the best way to meet security of supply and environmental objectives at the best value for money. It would maintain the advantages of a competitive market whilst enabling investors to see how potentially much lower load factors in the future would be compensated for by valuing the potential flexibility of those plants with a capacity payment.

28. Will the proposed package of options have wider impacts on the electricity system that have not been identified in this document, for example on electricity networks?

Liquidity will be damaged and market signals distorted. Plants in receipt of neither a CfD FiT nor a TCM would find it increasingly difficult to remain economic in the face of falling load factors as wind and nuclear generation increases. The high levels of volatility, combined with poor market liquidity, could lead to extreme pricing that will further deter generators (particularly small and independent ones) from taking part in the wholesale electricity markets. These effects could combine to deter investment in the flexible plant that is needed to manage the combination of demand growth and non price responsive generation.

29. How do you see the different elements of the preferred package interacting? Are these interactions different for other packages?

As recognised in the consultation

> "Interactions between all the policies to provide low-carbon generation revenue support (feed-in tariff and carbon price support) and a targeted capacity mechanism are limited and are not significantly altered by the choice of decarbonisation mechanism. The targeted EPS has very limited interactions with the other mechanisms."

As such our response below focuses on the low-carbon generation revenue support elements

Introduction of CfD FiT negates the impact of/need for CPS. Under a CfD FiT, low-carbon generation primarily receives a stable and certain revenue stream that is unaffected by the wholesale price. Therefore we would contend the impact on the wholesale price of the CPS element has limited consequence to new low-carbon generation. However existing low-carbon generation receives a windfall. This proposal also has the potential to further reduce market liquidity. CPS actually creates an additional level of uncertainty as it will be passed through at different levels depending on what type of technology is at the margin.

The interaction between a Fixed FiT and CPS would be similar, if not resulting in a more detached relationship. Presumably the level of FiT required will simply be lower by the estimated CPS pass through.

Under a Premium FiT low-carbon generation revenues are impacted by the CPS measure for as long as fossil-fuel generation remains at the margin. This result emphasises that a Premium FiT is the best mechanism in order for low-carbon generation to maintain a link to the wholesale market. Also, it does not further endanger the current low levels of market liquidity that would be impaired under a CfD FiT or a Fixed FiT mechanism.

The consultation document outlines two important consequences.

> "Firstly there is a positive impact on investment decisions: it reduces the liabilities for investors before the CfD is settled as they are getting a higher proportion of their revenues from the wholesale price. Carbon price support and CfD are both therefore contributing to this positive investment decision. "

We would equally contend that the ever increasing uncertainty that fossil-fuel generation will be at the margin leads to an investment risk for low-carbon generation

> "Secondly, there are important considerations for public finances as the flows from Government to generators would be lower than without carbon price support."

Whilst important to Government, this has no bearing on the investment decision faced by low-carbon generators. Additionally, this consequence does not impact the cost to the consumer whether through direct cost or indirect taxation routes.

We believe that the packages and policies contained in the consultation document do not provide a holistic approach to the challenges faced in the electricity market. They appear to be isolated policies to address individual objectives and do not take into account the unintended consequences on the remainder of the market.

Implementation Issues

30. What do you think are the main implementation risks for the Government's preferred package? Are these risks different for the other packages being considered?

We believe auctions will not be successful for the reasons outlined in question 31.
A CfD FiT would not be successful for the reasons outlined in question 26.
Targeted Capacity Mechanism would not be successful for the reasons outlined in question 21.
The combination of CfD FiT and TCM will seriously undermine the ability of the market to function properly as liquidity would be impacted and peak prices largely removed from the 'squeezed middle'. The proposed package will not lead to sufficient flexible generation being developed/maintained which will undermine growth in low carbon generation and could ultimately lead to an increase in emissions for the reasons outlined in questions 21, 26 & 31.

31. Do you have views on the role that auctions or tenders can play in setting the price for a feed-in tariff, compared to administratively determined support levels?

See answers below

 Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?
No, auctions work well where then is a single homogenous product and perfect information (seller and buyer knows cost, delivery time line etc), this is not the case for a FiT or Capacity Mechanism. The UK market has a very large Flexibility Gap going forward. It is not a case of a few thousand MWs of OCGT being required to meet peak demand.

Two examples illustrate the challenge faced. We know there is a high probability the wind will not blow tomorrow and that we will need plant to cover that supply gap. Alternatively we may find we have a less than expected drop in the wind and some plant is required to balance that supply in the next half hour. The type and quantity of plant required to cover these two eventualities are very different. An auction of this type will not attract a range of different types of plant. It will tend towards small, lowest capital cost plant, which will not necessarily be the most efficient. Because the RedPoint analysis underestimates the amount of flexibility required these plants will be required to run more than is anticipated potentially leading to an increase in emissions.

The TCM will undermine existing investment, upgrades to and new build plant outside of the mechanism. The TCM will also remove peak prices from the market further undermining the investment case for generation outside the TCM. Large and complex projects are unlikely to bid into the TCM as significant development funds will be required to be spent on the early stages of development in order to have a clear outlook on cost, engineering, development time, connection etc. As such, developers are unlikely to be willing to spend these types of funds on the basis they may win an auction if it is deemed that new capacity is required. Alternatively, developers who bid into the auction without having completed this kind of groundwork will be very uncertain of future development costs. As occurred with NFFO auctions in the UK, where only 25% of the auctions winners went on to develop their projects, this type of auction may well not result in the anticipated capacity threatening security of supply objectives.

□ Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?
It should exclude plant, or the portion of a plant, that is already receiving a FiT or other environmental incentive. Minimum flexibility criteria should be set and thereafter the market should be allowed to resolve what type of technology is appropriate. The total revenue received for more or less flexible plant should be reflected in the revenue achieved for a well functioning market.

□ How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?
We do not believe a CfD is the appropriate mechanism. We support a Premium FiT which can be designed very simply to reflect the value of the carbon savings or vintages of different technologies.

□ Are there other models Government should consider?
Yes, please see Appendix II

□ Should prices be set for individual projects or for technologies
Within a Premium FiT, different banding should be introduced to reflect the carbon benefits of different types of technology and vintage.

□ Do you think there is sufficient competition amongst potential developers / sites to run effective auctions?
No, auctions will not work for the reasons outlined in response to the start of Question 31. Government should seek to have a variety of different types of plant to meet the 'Flexibility Gap'.

□ Could an auction contribute to preventing the feed-in tariff policy from incentivising an unsustainable level of deployment of any one particular technology? Are there other ways to mitigate against this risk?
Yes it could. It will result in low cost, low risk plant on a relatively small scale. This will not be cost efficient, will not minimise emissions and the effect on the market could lead to security of supply issues. We do not believe there is any way in which an auction model can insure against this.

32. What changes do you think would be necessary to the institutional arrangements in the electricity sector to support these market reforms?

The preferred package would require a significant amount of institutional change and high administrative costs. It would eventually lead to a system operator controlled market as the 'squeezed middle' (those plants required to provide flexibility but excluded from the FiT or TCM) disappears. This would equate to Option 5 under Project Discovery.

It is not possible to comment in detail on what administrative changes would be needed as there are at present too many moving parts. However, it is clear a body needs to be made responsible for ensuring that the Flexibility Gap is analysed. This role would currently fall to NGC. A great deal of contracting and credit related issues would also be required with a CfD FiT. Conversely a Premium FiT would not require a great deal of administration or credit issues.

33. Do you have view on how market distortion and any other unintended consequences of a FIT or a targeted capacity mechanism can be minimised?

The complexity of the Government approach could form its own barrier to entry. The proposals could damage market liquidity by making large proportions of the market indifferent to market outturn prices. The distorting effect of a combined FiT and TCM package are so great that we do not believe the 'squeezed middle' (those generators outside the two incentive packages) will be able to continue to operate in the market profitably.

It is unclear if the FiT mechanism would be made available to imports. If so, this would further distort the European internal market. The Phase 3 EU ETS European carbon cap would be unaffected by these measures so overall carbon emissions would not reduced as a consequence.

34. Do you agree with the Government's assessment of the risks of delays to planned investments while the preferred package is implemented?

Existing investments should not be unduly affected as long as any revenue that would have been received under the Renewable Obligation is transposed into the new mechanism.

35. Do you agree with the principles underpinning the transition of the Renewables Obligation into the new arrangements? Are there other strategies which you think could be used to avoid delays to planned investments?

We believe that ROCs need to be transitioned into the new arrangements with an equivalent value but not through grandfathering of the mechanism. A Premium FiT would easily allow for those previously in receipt of ROC to receive a banded value that is the equivalent of their existing benefit. The costly apparatus of administering ROCs could be done away with by a simple monthly calculation of output x FiT value. The advantage for ROC recipients would be no credit risk. Their power could also be traded on the market in the normal way, thus supporting market liquidity.

36. We propose that accreditation under the RO would remain open until 31 March 2017. The Government's ambition to introduce the new feed-in tariff for low carbon in 2013/14 (subject to Parliamentary time). Which of these options do you favour:

□ All new renewable electricity capacity accrediting before 1 April 2017 accredits under the RO;

We believe the existing RO value should be maintained for plant up to 2017 but should be transmuted in to a Premium FiT value from 2018.

□ All new renewable electricity capacity accrediting after the introduction of the low-carbon support mechanism but before 1 April 2017 should have a choice between accrediting under the RO or the new mechanism.

Everyone should be moved on to a single platform from 2018.

37. Some technologies are not currently grandfathered under the RO. If the Government chooses not to grandfather some or all of these technologies,should we:

□ Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?

We have no view on the timing of banding reviews but do believe a Premium FiT can easily accommodate different bands for different technologies reflecting the level of their carbon emissions. It could also accommodate the 'transferring' of a number of existing incentives so that the proliferation of existing schemes and the overlap between them can be to be minimised.

□ Carry out an "early review" if evidence is provided of significant change in costs or other criteria as in legislation?

We are concerned that the possibility of an early review will be used to downgrade the issue around the security of supply risks. We believe they need addressing now in order to avoid an investment hiatus.

□ Should we move them out of the "vintaged" RO and into the new scheme, removing the potential need for scheduled banding reviews under the RO?
Yes, there is a proliferation of measures that often conflict rather than complement each other. To the extent possible, the value of measures on which investments were made needs to be protected but not the measures themselves. For example, if ROCs are grandfathered and then CPS introduced which will result in higher wholesale prices, then a windfall gain results to those with grandfathered ROCs. The number of low carbon measures in the UK market is now almost impossible to understand and the interactions between measures extremely complex. The layering of costs from EU ETS, CCSP, CPS, CRC, RHI, CCL, LEC, CCLA, NFFO, and ROCs etc has become impenetrable, providing a barrier to entry for new participants and investors and a complex regulatory framework for existing participants and Government to manage. We strongly favour a single platform, or at worst one on production and one on consumption. We believe a Premium FiT with various levels to reflect the requirements and carbon saving contributions of differing technology could be used to do this. A single banded FiT could be very effective in providing the right incentives and investment behaviour.

38. Which option for calculating the Obligation post 2017 do you favour?
□ Continue using both target and headroom
□ Use Calculation B (Headroom) only from 2017
□□ Fix the price of a ROC for existing and new generation

If FiTs are implemented, we do not believe that ROCs should be grandfathered as a separate market instrument as this will lead to overlapping policies and increased administration. We believe that the value of ROCs should instead be grandfathered into a future FiT and an appropriate banding be set for 'ROC vintages'

Appendix I - Oxera Analysis

This appendix contains extracts from a report by Oxera Consulting Limited prepared on behalf on the informal Independent Generators Group (IGG). The full report can be found within the IGG's Electricity Market Reform consultation response.

The report, commissioned by the IGG, provides an analysis of DECC's preferred approach to the introduction of a capacity mechanism in the GB electricity market. It examines the appropriateness of narrowly targeting capacity payments to certain reserve capacity, in order to meet a centrally determined target capacity margin.[1]

The report provides an initial assessment of the change in system conditions, and the accompanying risks that may be caused by increased wind generation alongside the expansion of nuclear and carbon capture and storage (CCS) projects in the GB electricity market.

In particular, analysis is presented to examine the extent to which system 'flexibility requirements' are likely to change over time. That is, the hourly and daily changes in demand-net-wind, as well the economic incentives that may be present in order for existing and potential flexible capacity to be available to meet this requirement - a challenge that is distinct from the need to provide a capacity margin above system peak demand.[2]

The analysis provides a starting point with which to undertake an initial assessment of whether DECC's preferred targeted capacity mechanism (TCM) may alleviate or exacerbate these risks, and the scope for potential price distortions and the impact that this may have on investment incentives.

The report then sets out some initial considerations on an alternative mechanism that could be better equipped to address the flexibility challenge posed by the possibility of early retirement of existing flexible plant, and weakened investment incentives that may otherwise deter investment in sufficient new flexible capacity to deliver longer-term security of supply (see Appendix II).

Flexibility requirements

With regard to system flexibility requirements, the key findings of the analysis are that:

– changes in the generation mix could increase GB flexibility requirements, which are governed and dictated by short term variations in demand-net-wind, and as such, are different to the traditional need to meet system peak demand.

– flexibility can be provided from flexible generation and demand side response (DSR), with short-term responsiveness on the generation side governed by the difference in plant's maximum and stable export limits, with further constraints determined by plant ramp rates and whether the plant is already synchronised.

– a 'flexibility gap' - defined in this report as the situation in which short term responsiveness from flexible capacity could be insufficient to meet hourly demand-net-wind variations - could emerge by 2020, regardless of whether system capacity is sufficient to meet peak demand.

Flexibility investment incentives

With regard to flexibility investment incentives, the key findings of the analysis are that:

– absent intervention, there might be insufficient incentive to invest in adequate flexibility. This is because thermal plant could be required to increasingly rely on short-term revenues that encompass increased risks that may not be hedged, and are subject to the threat of distortions from 'out of market' actions;

[1] DECC (2010), 'Electricity Market Reform. Consultation Document', December.

[2] Flexibility requirements are likely to include the ability to meet hour-to-hour variations as well as increased variation in daily peaks and toughs of demand-net-wind. The analysis in this report focuses on the ability to respond to hourly variations.

– specific risks include the ability to capture short-term price spikes caused by wind variations, and the increased risk to plant performance from more frequent output variations;

– these risks are likely to be larger for non-integrated and non-portfolio players—uncertainty over future operating conditions could reduce the scope to contract forward and sell power sufficiently far on advance at attractive terms, as well as hedge price risk. [3]

DECC's preferred TCM does not attempt to mitigate these risks, and may exacerbate the risk of price distortions. Out-of-market actions (or even the potential for such actions) by the operator of capacity contracted under the proposed TCM, can directly affect price and volume expectations for balancing and ancillary services. In particular:

– they may reduce balancing volumes procured through the market, and hence expectations of balancing mechanism prices;

– there may also be a reduction in other reserve contracts and ancillary service requirements, leading to reduced price expectations for contracts outside the proposed mechanism.

The EMR recognises that potential distortions could arise through the effect of dispatch of the targeted capacity on peak prices, and that these distortions, along with the risk that an increasing proportion of capacity may need to be contracted under the proposed mechanism 'could undermine the mechanism's ability to ensure secure supplies of energy'.[4]

DECC's proposed TCM is similar to the Swedish model that makes use of Peak Load Reserves (PLR). There is evidence from regulators and academic studies that potential price distortions remain a risk under this model and should generally be avoided.[5]

[3] Hart (1988) describes how the firm as an institution can be thought of as arising from the incompleteness of contracts and the need to allocate residual control rights. See Hart. O (1988), 'Incomplete contracts and the theory of the firm', Journal of Law, Economics and Organization.

[4] DECC (2010) Op. Cit. p94. The EMR consultation recognises that the potential effects on peak prices and the 'slippery slope' effect could undermine the performance of the proposed TCM.

[5] See for example, Svenska Kraftnät (2002), 'Effektförsörjning på den öppna elmarknaden, Utredningsrapport', January 10th; Johansson, T. and Nilsson M. (2010), ' Signs of stress II: The customer strikes back', April 9th; Nord Pool Spot (2010), 'Handling of the peak load reserves in the spot market', October 1st; Botterud, A. and Doorman G. (2008), 'Generation Investment and Capacity Adequacy in Electricity Markets', International Association for Energy Economics; Energy Markets Inspectorate (2006), 'Price Formation and Competition in the Swedish Electricity Market', report 2006:13; NordREG (2009), 'Peak Load Arrangements, Assessment of Nordel Guidelines', report 2/2009; NordREG (2010), 'Assessment of Nordel's revised Guidelines for transitional peak load arrangements', March.

Figure 1 Demand net wind distributions, winter 2020

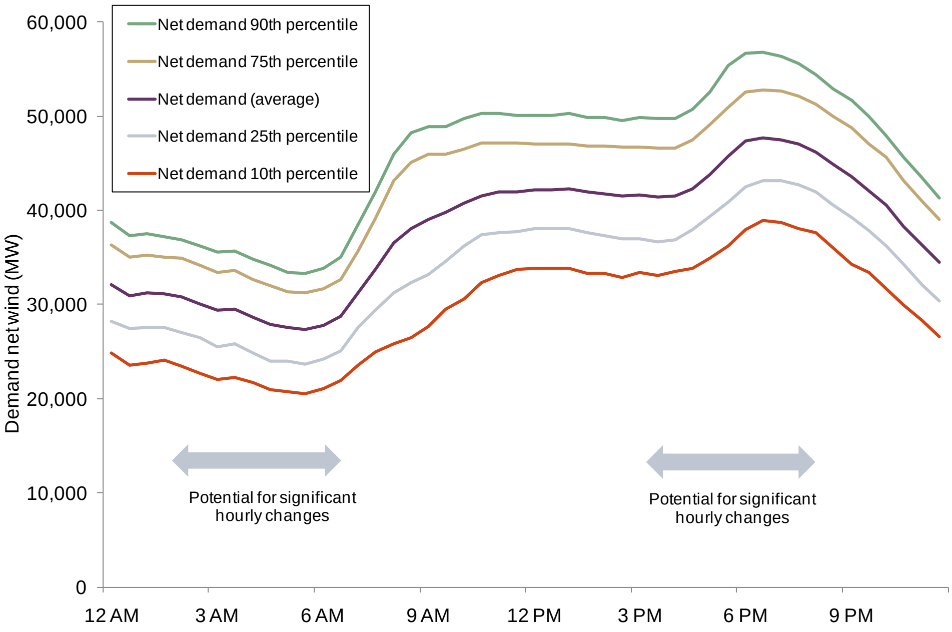


Figure 1 presents demand-net-wind curves for a representative winter day in 2020. The shapes of the curves and their distributions are based on Monte Carlo simulations of demand and wind output over a representative day. The simulations are based on the historical distributions of demand and wind output, and incorporate correlations between demand and wind across consecutive periods as implied by historical patterns.

Wind capacity has been modelled to grow from its existing level of around 5GW to 20GW by 2020 under the existing Renewables Obligation. Demand is assumed to grow at a rate based on National Grid's Seven Year Statement (SYS) and is broadly consistent with DECC's assumptions. This equates to a compound annual growth rate of 0.1% between 2010 and 2030.

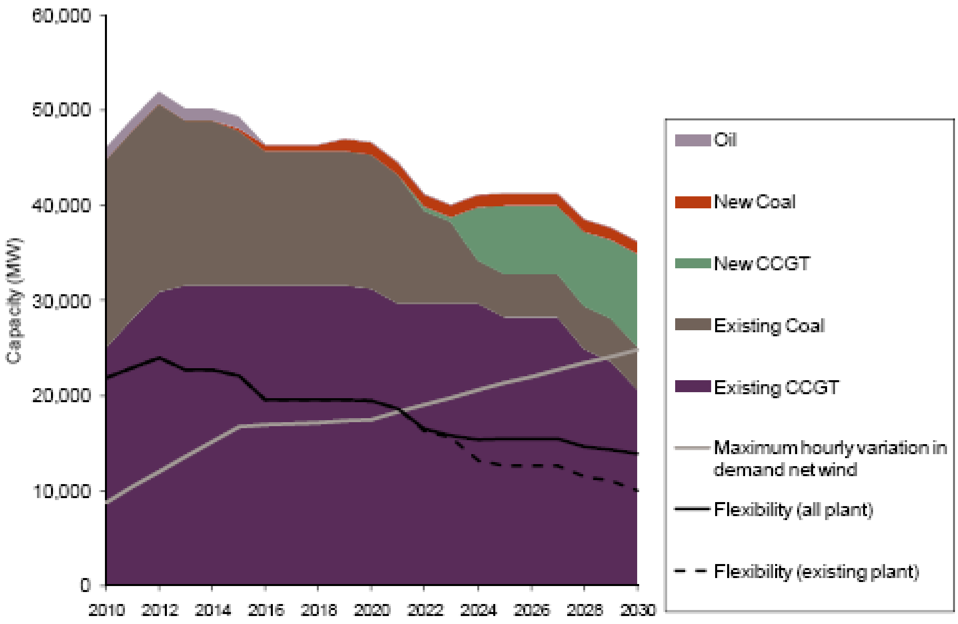
The figure highlights:

– the potential range and uncertainty in load on thermal plant by presenting alternative points on the distributions of demand net wind (defined by percentiles); and
– the potential for significant hourly changes in demand net wind when going from peak to off-peak periods and vice versa within a particular distribution of demand net wind.

Instances of relatively high demand-net-wind might be expected to lead to potential price spikes, and profitable opportunities for flexible plant to provide output to meet this demand if they have sufficient foresight and responsiveness. Periods of low demand combined with high wind creates the risk of low (or negative) power prices.

These dynamics affect the revenue potential of thermal plant, as well as their costs, as variations in load are likely to increase the operating and maintenance costs of plant as a result of increasing ramp up and down at frequent intervals, as well as the loss in thermal efficiency that can arise from operating below maximum output.

Figure 2 Flexibility requirements versus flexible capacity



Note: Retirement profiles of existing plant and investment in new plant are based on efficient dispatch and existing price dynamics that reflect the historical relationship between price levels and capacity margins, and absent possible price distortions. Capacity is de-rated to reflect average availability. Capacity figures exclude nuclear and CCS, which are deemed to be inflexible (both due to technical restrictions and because they are likely to operate at high load factors and to have limited scope to provide additional output). It also excludes pumped storage, which cannot be drawn on frequently once depleted, and is often used to provide shorter-term (sub-hourly) response.
Source: IEML, and Oxera analysis.

Figure 2 highlights the following:

– In the absence of investment in new flexible plant in the next few years, system flexibility could become tight from around 2020;

– investment in new and existing capacity would be essential to provide required flexibility beyond 2020;

– flexible capacity may be insufficient to meet demand variations by 2030 regardless of whether system capacity is sufficient to meet peak demand.

As noted above, the outturn supply of flexibility may be less than that shown in Figure 2, where flexible capacity is already operating above its stable export limit, or has reduced responsiveness if it must start from cold.

The analysis suggests that:

– greater deployment of wind plant is likely to result in increased variability in output provided by thermal plant;

– peak demand is likely to remain unchanged as a result of increasing wind generation, although peaking and mid-merit plant are required to operate, and recover their fixed and capital costs over fewer hours;

– the main impact of wind capacity is to significantly increase the flexibility requirements on the system instead of on its ability to meet peak demand;

– system flexibility is expected to decline over time as existing flexible (ie, thermal) plant shut down and there is increased deployment of inflexible (ie, wind) plant;

– by 2030, a ‘flexibility gap’ could develop, based on intermittent and retirement decisions under the current forward curve for gas and coal prices, and short-term flexibility provision by generating plant equal to the difference between plant’s maximum and stable export limits and ramp rates. This would be due to closures of existing thermal capacity, with insufficient volume of new CCGT expected to be built;

– any market distortions that lead to early closures of thermal plant or dampen investment incentives are therefore likely to reduce system flexibility and to hamper the ability of the system to respond to demand variations.

Increased reliance on short-term revenues

With increased wind penetration, short term variations in wind output is likely to increasingly determine system operating conditions. Flexible plant operating at low load-factors that has traditionally operated in relatively well foreseen periods of high demand (eg winter peak periods), is more likely to be required to generate in periods of system tightness, driven more by hourly wind variations than the underlying levels of demand.

This uncertainty for flexible plant over their future operating patterns in the days and months ahead of real time might be expected to reduce the scope for such plant to contract in forward markets to sell this power ahead of time, as well as hedge against possible price levels in those periods. The difficulty may arise in specifying within a long-term contract exactly under what conditions the plant should operate given the number of possible supply and demand conditions.

This prospect may be more acute for independent generators than vertically integrated companies, where the supply affiliates of the latter can draw on their generation portfolio in circumstances that are difficult to anticipate or define far in advance.

Increased risks of short-term revenues

Increased reliance on short-term trades, especially for independent generators as described above, might also be expected to be accompanied by greater risk associated with those revenues.

The risks might be expected both on the revenue and cost-side and include:

– the risk of a plant being unavailable at short notice to meet changes in demand-net-wind in order to capture price spikes;
– the risk of distortions to scarcity prices during periods of system tightness caused by ‘out of market’ actions (discussed below);
– increased stresses imposed on plants stemming from variations in load, and thereby leading to higher maintenance costs.
– Increasing thermal operation below maximum thermal efficiency as plant are required to operate for increased periods below maximum output

Furthermore, the penalties associated with imbalance positions are likely to increase with the anticipated growth in penetration of intermittent generation since the system as a whole is more likely to be long or short by a greater amount in any given period. This might be expected to increase the risk of more severe penalties for individual generators finding themselves out of balance.

To the extent that the risk from individual plant imbalances can be diversified by holding a portfolio of generation, or self-balancing through vertical integration, this dynamic could act to promote the need for a portfolio of generating plant, thereby increasing barriers to entry in generation.

Potential price distortions

The EMR consultation suggests that a TCM would only be required to procure a small amount of capacity and that any potential distortions would therefore be relatively small.

Increased reliance on short term trades and the possibility that the revenues associated with those trades are likely to become increasingly risky with greater wind penetration is likely to exacerbate the potential threat of price distortions from the proposed TCM.

The potential price distortions lead to the following dynamics.

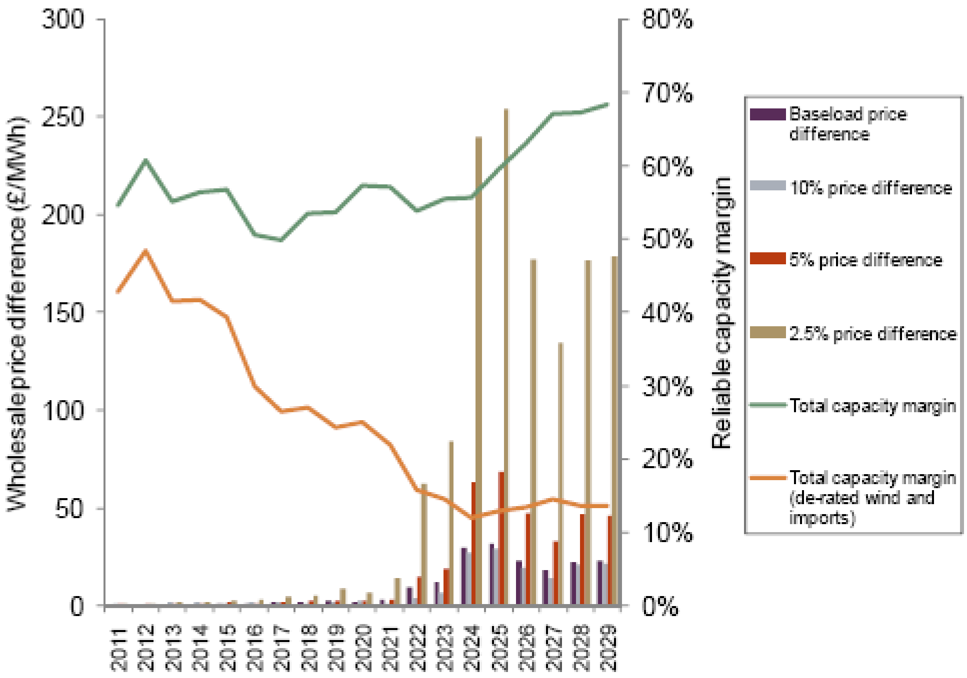
– ‘Out of market’ actions (or even the potential for such actions) by the operator of capacity contracted under the proposed TCM, can directly impact price and volume expectations for those services. In particular:

  – it may reduce balancing volumes procured through the market, and hence expectations of balancing mechanism prices; and

  – there may also be a reduction in other reserve contracts and ancillary service requirements, leading to reduced price expectations for contracts outside the proposed mechanism.

– Capacity that would otherwise be expected to receive balancing mechanism (BM) or reserve contract revenues may therefore be prepared to accept lower prices in wholesale markets rather than risk receiving depressed prices for balancing and ancillary services

Figure 3 Illustrative price distortions from out-of-market actions (5.4GW)



Note: Total capacity margin represents the excess of total capacity (including imports) as a percentage of peak demand. A total capacity margin is also shown after adjusting for the capacity credit of wind (which varies according to wind penetration), and de-rating imports.
Source: Oxera.

An illustration of the level of price distortions that could arise from this additional capacity can be seen by comparing the impact on the scarcity component of prices with and without the additional capacity that is contracted under the proposed mechanism.

Analysis undertaken for the EMR suggests that between 5.4GW and 10.7GW could be required under the proposed targeted mechanism. This represents around a 5-11 percentage point increased in the capacity margin in 2025 (based on total capacity of 96GW), or 7-15 percentage point increase in the total reliable capacity margin (based on reliable capacity of 70GW).

Figure 3 highlights the impact an additional 5.4GW could have if this capacity were to be fully reflected in the scarcity component of prices. The price impact might be expected to be greatest when capacity margins are tight, such as in 2024 and 2025. The impact of this additional capacity could decrease peak prices (specifically those that are only observed 2.5% of the time or less) by up to £300/MWh (relative to a base case of around £1,000/MWh), and depress baseload prices by as much as £30/MWh.

If these effects were to feed into investors' price expectations, there could be the risk that tendered capacity would 'crowd out' market-driven investments.

The analysis suggests that:

– the role of thermal generation is likely to change due to the greater deployment of wind generation, by making their ability to operating in a flexible and responsive manner increasingly valuable;

– the nature of wind generation may be likely to make flexible generators more reliant on short-term trades and ancillary service revenues;

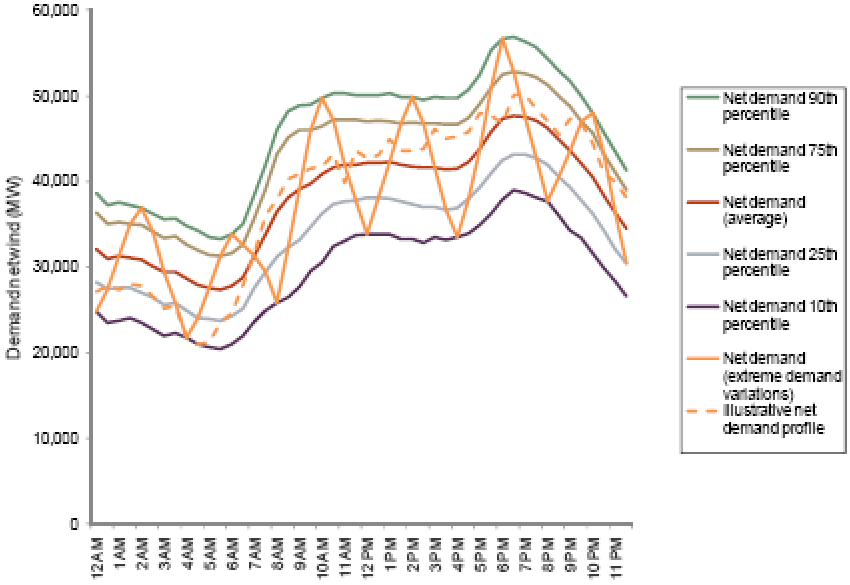
– prices for power sold closer to real time and in response to uncertain variations in wind output might be expected to be higher because of the greater risks involved, notably the greater stresses and maintenance costs imposed on plants stemming from variations in load and uncertain operating patterns;

– price capture may become a significant risk to flexible generators if it is difficult to anticipate periods of system tightness from variations in wind output far in advance;

– and the proposed TCM could exacerbate these risks by increasing the threat of potential price distortions through out-of-action market actions (or even the potential for such actions) by the operator of contracted reserve capacity – illustrative calculations suggest that potential price distortions could be as high as 25%;

– these risks could be larger for non-integrated and non-portfolio players.

Figure 4 Demand net wind distributions, winter 2020



Note: The illustrative net demand profile shows the hourly variation in demand net wind for a single simulation based on Oxera modelling, and highlights that extreme within-day and hour-to-hour variations are possible.
Source: Oxera analysis.

Variability in demand is likely to result in increased requirements on thermal plant to ramp up and down in order to be able to generate in periods when prices are greater than their marginal costs. Technical constraints that prevent frequent ramping up and down are likely to either prevent plant from benefitting from peak prices or require them to operate in low price periods in expectation of higher prices in future periods.

This section assesses the potential impact of demand variability by considering plant operating patterns under three alternative demand patterns:

– Average demand—this estimates average demand levels for each half-hour from the Monte Carlo simulations of half-hourly demand.

– Extreme demand variations—this assumes that demand shifts from one percentile of its distribution to the next from half hour to half hour, and as such may be considered an extreme case due to correlations in wind output across consecutive half hours.

– Representative net demand profile—this presents a representative demand net wind pattern obtained from the Monte Carlo simulations of demand and wind. While this distribution shows greater variations than the ‘average demand’ distribution, the demand variations are less extreme that in the ‘extreme demand variations’ case.

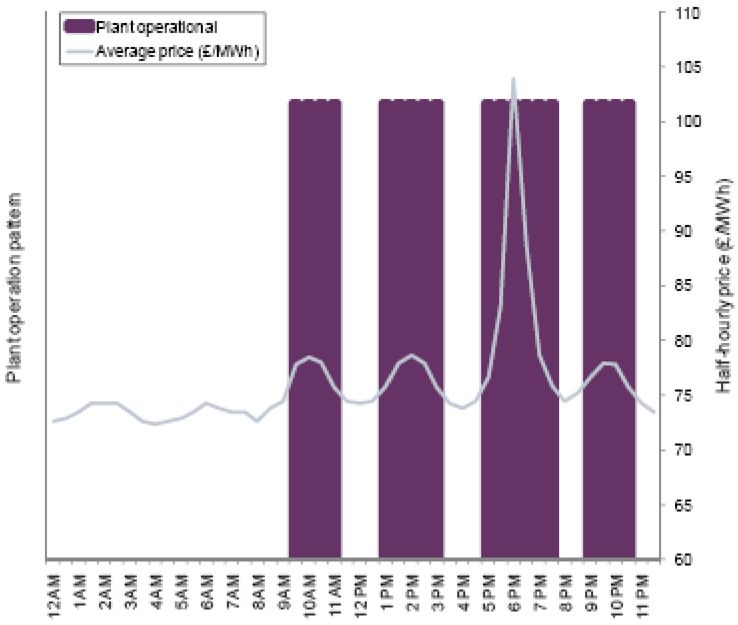
These demand patterns are set out in Figure 4, which presents demand net wind distributions in winter 2025 for a range of points across the Monte Carlo simulations of half-hourly demand and wind patterns. The figure highlights the greater variability in the ‘typical net demand profile’ distribution than in the ‘average demand’ profile, with the greatest variability being in the ‘extreme demand variations’ profile.

The figure highlights the extent of flexibility requirements by 2020, showing:

– large variations in demand across a day, with average demand ranging from 27GW to 48GW; and

– large hour-to-hour variations in demand, with maximum hourly changes of up to 17GW.

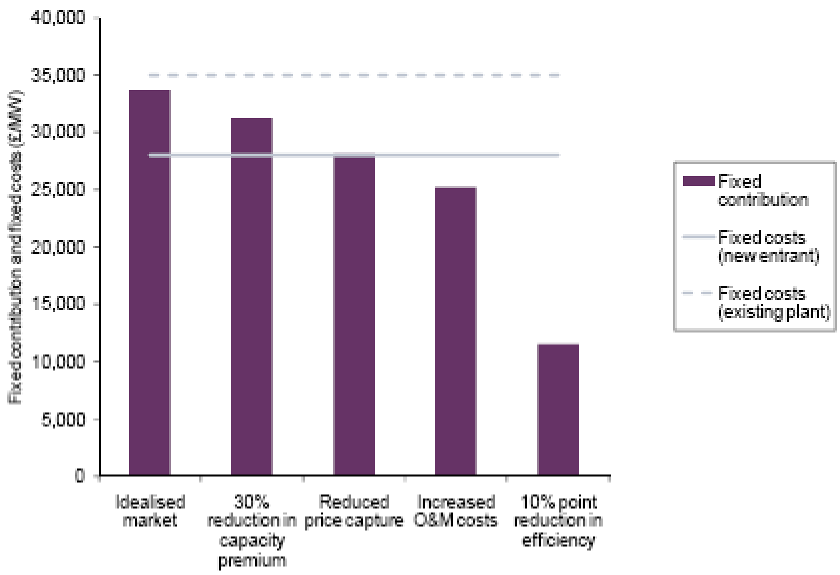
Figure 5 Daily operating pattern of existing CCGT, extreme demand variability, winter 2020



Source: Oxera analysis.

Flexible plant are required to ramp up and down more frequently under the extreme demand distribution to enable recovery of prices associated with high demand/low wind conditions. However, high start-up costs are likely to reduce the ability of price capture. It is likely that plant will continue to operate part-loaded at low demand/high price periods, creating the risk of operating during low or negative price periods.

Figure 6 Impact of market distortions, existing CCGT, 2020



Note: Data is in real 2010 prices.
Source: IEML, and Oxera analysis.

The impact of these effects on fixed cost recovery existing CCGT is illustrated in Figure 6. The figures show the returns to plant under an 'idealised market', where market participants have perfect foresight, there is efficient dispatch and there are no additional costs associated with increased output variability. The impact of relaxing each of these assumptions is assessed to determine the viability of existing thermal plant remaining open.

The approach to assessing the impact of relaxing ‘perfect market’ modelling assumptions is as follows:

– Distortion of peak prices—the capacity premium component of prices is assumed to fall by 30% consistent with the illustrative impact of an additional 5GW on capacity margins.

– Price capture effects—the price capture effects have been tested by assessing the impact of a 10 percentage-point reduction in plant load factor.

– O&M costs—to determine the effects of an increase in O&M costs, the variable O&M costs of a CCGT are assumed to increase three-fold (consistent with a 30% increase in variable costs).

– Efficiency—in assessing the impact of lower load factor operations on plant efficiency, the efficiency of existing CCGTs is assumed to fall by 10% points based on analysis by IEML.

The analysis highlights that by 2020 the existing CCGT is unable to meet its fixed costs even under idealised market conditions. On relaxing the typical ‘perfect market’ modelling assumptions and considering the likely costs of increased output variability, and distortions created by a mechanism similar to TCM, the shortfall in the fixed cost recovery of plant increases substantially. Existing CCGTs would, therefore, require additional support mechanisms to enable them to remain open.

The analysis suggests the following:

– Thermal plant is likely to operate for fewer hours over time with increasing deployment of wind.

– Thermal plant is likely to be required to ramp up and down more frequently given variations in wind output, to enable price capture. However, technical constraints could prevent frequent variations in output, thus affecting plant’s ability for price capture and risks of facing low or even negative prices.

– The shift from operating baseload to operating in a proportion of peak periods is likely to increase dependence on peak prices to enable recovery of fixed costs. Mechanisms like the TCM that distort peak prices could therefore worsen plant economics.

– Although average prices realised by existing thermal plant may be expected to increase as they operate in peak periods instead of operating baseload, declining load factors could result in lower returns.

– Low load factor operations are also likely to result in a reduction in plant efficiency and an increase in its O&M costs, further worsening plant economics.

– Under the current forward curve for gas and coal prices, power prices in an energy-only market are unlikely to be high enough to enable existing thermal plant to recover their fixed costs and remain open. In addition to revenues earned through the energy-only market, additional support mechanisms are likely to be required.

Appendix II - Potential GB capacity mechanism design

This appendix proposes a potential GB capacity design mechanism and is included within the report by Oxera Consulting Limited prepared on behalf on the informal Independent Generators Group (IGG). The full report can be found within the IGG Electricity Market Reform consultation response. The following is included within section 5 of the Oxera report.

The sections prior to section 5 set out that there may be a need for a mechanism to encourage the retention of existing flexible capacity, and construction of additional flexible capacity.

The analysis has highlighted that the proposed TCM, which is narrowly focused by design, may fail to attract sufficient market-wide investment in flexible capacity, and may further create distortions that deter investment in capacity outside the proposed mechanism.

This section presents an alternative solution that attempts to achieve a balance between simplicity and transparency, while sending appropriate signals to encourage investment in flexible generation.

Further analysis would be required to produce a full cost benefit analysis to compare the outcomes under alternative models.

The key messages are highlighted in Box 5.1.

Box 5.1 Key messages

A possible GB flexibility mechanism

– Sufficient flexible capacity may not be incentivised under DECC's proposed reforms;
– Key elements of any new scheme are to be to provide transparent, market-wide signals;
– A stable, fixed revenue mechanism based on system requirements could be used to provide additional incentives that increase as the penetration of wind capacity increases.

Priorities for mechanism design

DECC set out in the EMR consultation that it would assess the effectiveness of the market reform options along four broad principles.

– **Cost-effectiveness –** options for reform should preserve competitive pressures where possible, and be affordable to consumers.

– **Durability and flexibility –** proposals should be robust to a number of unlikely outcomes (regarding prices and technology costs).

– **Practicality –** new mechanisms should be able to work in practice and achieve a manageable transition.

– **Coherence** – policies must combine in a complementary manner.

From the discussion of potential distortions of the proposed TCM in section 3, it would appear that a mechanism that achieves long run cost effectiveness should look to:

– mitigate the increased risks faced by flexible plant as wind penetration increases;
– minimise entry barriers that could accompany a non-market based and discretionary mechanism such as the TCM.

On durability, flexibility and practicality, it would seem appropriate that any new mechanism should:

- provide greatest signals to invest as the flexibility requirements from intermittency increase;
- accommodate increased DSR, and spur innovation and increasing participation from the demand side.

International experience of capacity mechanism design can also provide a useful guide to possible design features for a GB flexibility mechanism even though the capacity mechanisms implemented to date have been designed to meet demand peaks and not flexibility requirements.

Two key lessons from international experience (as highlighted from the Swedish experience described in section 3 and from US markets described in Appendix 1) are that:

1. Selective tendering and discretionary use of reserve capacity can create price distortions, and this prospect can reduce generators' revenue expectations and subsequently deter investment.

2. Schemes that rely on decentralised pricing, ex post rebate schemes, or additional regulations to limit total revenues can become administratively complex and open to the risk of gaming.

This suggests that, given uncertainty over whether market-driven investment may be sufficient to provide the required GB system flexibility, as highlighted in section 2, two central features of a possible flexibility mechanism for the GB market could be:

- to be transparent and provide market-wide investment signals to flexible generation and flexible demand;
- to provide revenues from a centrally determined pot, the value of which is reflective of system requirements.

Alternative market design: a possible flexibility mechanism

Figure 3.1 and Table 3.1 set out the steps in which a possible 'fixed revenue' flexibility mechanism could be implemented.

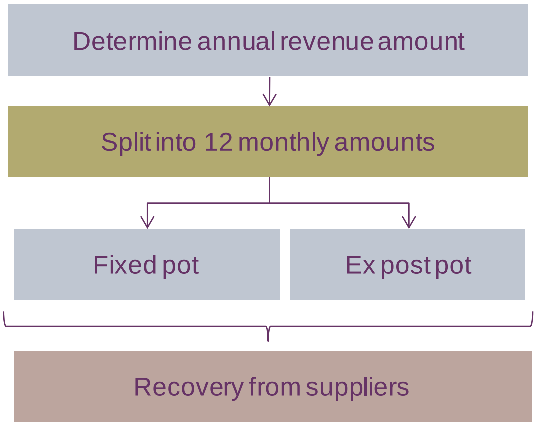
- An annual flexibility requirement (GW) could be calculated based on wind penetration and expected variations in output, inflexible demand variations, and a security standard eg, a requirement to meet 3 standard deviations (or 99.7%) or expected hourly variations in demand-net-wind;
- A total annual revenue amount could be determined based on system flexibility requirements and the costs of the marginal provider of flexibility;
- The revenue pot could be split between different time periods, based on a combination of anticipated flexibility requirements and ex-post demand and wind outturn (so that greatest revenues are available when flexibility requirements are highest);
- All flexible generation and demand participants available within a given period could be eligible to receive a share of the revenue available in that period.

A worked example of what this would mean for consumers and generators is set out in Box 5.2.

The advantages of such a 'fixed revenue' mechanism are that:

- a degree of stability can be introduced into the flexibility payments through tailoring the revenue split between the fixed pot and ex-post pot;
- the mechanistic calculation of annual revenues based on wind penetration, demand growth and known statistical distributions can help promote longer-term investment signals;
- short-term signals can be generated to create the incentive for flexible generation and demand to be available through the ex-post revenue allocation.

Figure 5.1 Allocation and recovery of flexibility payments



Source: Oxera

The key design elements are summarised in Table 5.1.

Table 5.1 Key design elements

Design element	Operational details
Annual revenue amount	Annual flexibility requirement calculated based on expected half-hourly wind variations and inflexible demand variations throughout the year (in MW) to meet a reliability standard.* Annual revenue amount calculated by multiplying the flexibility requirement by the fixed costs of the marginal flexibility provider *minus* the expected energy and ancillary revenues of the marginal flexibility provider.** * A reliability standard could be equal to the flexibility required to meet 95% or 99% of expected hourly variations in demand-net-wind. **This approach has been adopted in the SEM but in the context of a Best New Entrant Peaker. In a possible flexibility mechanism, these revenues could be based on a rolling average of output of flexible plant— a technique adopted in PJM.
Monthly amounts	Monthly payments to generators/demand participants could be profiled within sub-periods (daily or half hourly) according to a pre-determined ex-ante fixed element in each period and an ex-post variable element. Allocations could be based on the difference in supply and system demand for flexibility: **Flexibility margin** = {supply of flexible capacity + demand} minus {changes in demand-net-wind*} *excluding flexible demand
Eligibility	The eligibility of plant to receive payments could be based on their ability to provide flexible capacity/demand.
Recovery from suppliers	A pro-rated levy could be introduced based on the level of inflexible demand.
Data requirements	Wind penetration and typical half-hourly variations. Inflexible demand levels and typical variations. Unit capacities obtained from generators. Outturn wind and demand changes and flexible generation and demand availability.

Source: Oxera

Eligibility

The proposed mechanism could promote investment and participation from a wider range of flexibility providers than DECC's proposed TCM.

Eligible generators could be required to demonstrate a minimum flexibility standard, and generators who receive a FIT (or other incentive) under the proposed reforms could be excluded.

If appropriate, an additional complexity for plant which has some ability to provide flexibility and a low carbon inflexible element such as CHP, nuclear or some biomass plant could declare part of their plant low carbon inflexible and part flexible. Such a plant could then have a proportion of its capacity rewarded in the FIT mechanism and part in the Flexible Capacity Mechanism. Demand Side Response and Storage projects would also be eligible for the capacity payment.

Box 5.2 Possible flexibility mechanism—illustrative example

The table below presents illustrative calculations for the possible flexibility mechanism.

Calculation step	Comments
Annual revenue amount	
Annual flexibility requirement	Maximum expected hourly demand-net-wind variations based on wind and demand distributions: 17GW (2020); 25GW (2030) Flexibility standard: requirement to cater for 99.7% (three standard deviations) of all simulated hourly demand-net-wind variations. Range of expected hourly demand-net-wind variations that encompass 99.9% of expected distribution: 15GW (2020); 17GW (2030)
Annual revenue amount	Marginal source of flexibility: OCGT Fixed and capital costs: £100/kW Load Factor (LF): 0% Wholesale contribution = LF x (realised price-variable costs): 0 Annual revenue amount = (fixed & capital costs – contribution)* flexibility requirement £1.5 billion (2020): (100-0)*15 £1.7 billion (2030): (100-0)*17
Daily profile of payments	
	Assumed ratio of fixed and ex post revenue: 50:50 The figure below shows the variation in demand net wind for an illustrative day in 2020 and the associated flexibility payments, paid in proportion to the absolute half-hourly change in required flexibility. Total payments (fixed and ex post) range from £3–£10/MW in each half-hour.

Source: Oxera.

Assessment

Table 5.1 provides a qualitative assessment of the fixed revenue mechanism against DECC's performance principles.

Table 5.1 Assessment of Flexibility Payment Mechanism against DECC criteria

Criteria	Assessment
Cost-effectiveness	The relatively wide-based flexibility mechanism could explicitly include DSR, as well as promote investment in new flexible plant, and life extensions to existing plant, promoting competition in the wholesale market. A flexibility revenue stream separate from imbalance risks and wholesale energy transaction costs may be more likely to promote entry from non-integrated or portfolio generators. Any potential over-subsidy would be likely to be eliminated through competition and liquidity improvements as recognised by DECC, and through a mechanistic calculation of expected energy revenues in determining the revenue pot.
Durability and flexibility	The mechanism could include DSR and therefore might be likely to have greater longevity than DECC's proposed TCM. Annual calculations of the revenue pot would reflect changes in technology costs, expected wholesale revenues (and commodity price movements), as well as wind deployment.
Practicality	Flexibility requirements are likely to be small in the near-term and grow over time. The proposed mechanism would therefore entail a relatively small revenue pot at low wind penetration, and increase as the system flexibility requirements increase.
Coherence	Eligibility criteria could be used to ensure that flexibility payments are awarded to plant that do not receive the proposed FITs. Alternatively, generators could opt to declare a proportion of their capacity that is inflexible and eligible for FITs and the remaining proportion that is eligible for flexibility payments.

Summary

This section has examined the features of a possible mechanism that may be required to mitigate the likely increase in risks faced by flexible plant with increased wind penetration in order to promote the retention of existing flexible capacity and construction of additional capacity.

Consistent with the principles put forward by DECC to assess alternative policy proposals, an appropriate flexibility mechanism might be expected to:

- mitigate the increased risks faced by flexible plant as wind penetration increases;
- minimise entry barriers that could accompany non-market based and discretionary mechanism such as the TCM;
- provide greatest signals to invest as the flexibility requirements from intermittency increase;
- accommodate increased DSR, and spur innovation and increasing participation from the demand side.

A fixed revenue mechanism may be able to strike an appropriate balance between creating the right investment signals for providers of flexibility while minimising complexity and the risk of gaming. The advantages of such a mechanism are that:

- a degree of stability can be introduced into the flexibility payments through tailoring the revenue split between the a fixed element and one related to ex-post system conditions;
- the mechanistic calculation of annual revenues based on wind penetration, demand growth and known statistical distributions can help promote longer-term investment signals;
- short-term signals can be generated to create the incentive for flexible generation and demand to be available through the ex-post revenue allocation.

Appendix III - ConocoPhillips' Carbon Price Support Consultation Response

Introduction

ConocoPhillips (U.K.) Ltd welcomes the opportunity to respond to the 'Carbon Price Floor' consultation. Our primary focus in this response is on the impact to CHP. We expect investment in low-carbon electricity to be driven predominantly by the measures introduced as part of the broader EMR package (CfDs or FITs). As currently proposed, the CPS mechanism would disincentivise new investment in CHP and may lead existing CHP to de-classify with a resulting increase in emissions.

> "CHP stations are energy efficient in operation, providing very significant fuel savings and thus cost and efficiency savings, over conventional forms of electricity generation and heat supply. CHP provides one of the most cost-effective approaches for reducing CO2 emissions and plays a crucial role in the UK Climate Change Programme."
>
> *This is an extract from the HMRC Notice CCL1/2 (July 2010).*

ConocoPhillips is an international energy company operating in over 30 countries. Our Power Development group in the UK are therefore competing internally for investment funds on an international basis. Our interest in the UK power market is in projects related to our core business assets. This resulted in us building the largest CHP in the UK adjacent to our Humber Refinery. The Immingham CHP project provides steam to Total's Lindsey and ConocoPhillips' Humber Oil Refineries which together represent 25% of UK refining capacity. The first phase of the Immingham CHP project was 730MW which was commissioned in 2004. A second phase was commissioned in 2009, which increased the plant capacity to 1220 MW.

ConocoPhillips also has section 36 consent for an 800 MW CHP facility at Seal Sands in Teesside adjacent to the ConocoPhillips-operated Teesside Oil Terminal. We are currently looking at the investment case for this project and, were this investment to proceed, it would supply reliable low cost steam to the Terminal and a number of third party facilities in the area. ConocoPhillips' UK power development group is also analysing both biomass and peaking enhancements to our Immingham site.

As a Downstream operator in the extremely competitive refining sector, ConocoPhillips has invested large amounts of money in making the Humber Refinery one of the top 10% most energy efficient European refineries. This has included the Immingham CHP plant, which was the best technology available to us in lowering our carbon footprint. The investment was undertaken taking account of UK and European government support for CHP developments. This support included CHP targets, the Cogen Directive, Enhanced Capital Allowances and the introduction of Levy Exemption Certificates for Good Quality CHP plant. Such support has been reinforced more recently as per the quotations in this Introduction.

In contradiction to the measures described above that support CHP investment, we have significant concerns on the potential impact of the UK Electricity Market Reform proposals and, in particular, the CPS consultation on the CHP sector. Charging CHPs CPS on the fuel used to generate heat means that CHP projects will be disadvantaged versus the separate production of power and heat. The vast majority of industrial hosts have Climate Change Levy Agreements (hence are 65% exempt from CCL) or are in CCL exempt sectors such as refining and would therefore not be subject to the CPS mechanism or CCL for the production of heat in standalone boilers. The incentive, as currently drafted, would mean that one such site that saves carbon by

CHP investment (as CHP emits less carbon than the separate production of power and heat), would be paying more carbon tax than a site that imports power and has standalone boilers

One further area for concern is the layering of costs to industry, additional to those being borne by European competitors. At the levels suggested in the consultation, by 2030 UK industry might be paying carbon costs in electricity prices several times greater than the rest of Europe, when CPS and CRC are taken together. In many industries this will be sufficient to produce a significant impetus for imports. It is essential that the total impact of climate change measures on costs is clearly assessed.

The treatment of CHP under the CPS Mechanism disadvantages almost all CHP as shown by the CHPA analysis (Annex II). We believe this is an unintended consequence. This analysis has been shared with DECC, Treasury and HMRC. The analysis also shows that the disadvantage could be removed, by exempting CHPs from CPS on the fuel used to generate Good Quality heat, through a simple amendment to the current CHP Quality Assurance process (see Annex III). This solution would ensure CHP remains competitive versus the separate generation of heat and power with no material impact on administration or costs.

Should the CPS mechanism go ahead as proposed, we believe it will preclude further significant investment in CHP and may lead to existing facilities de-classifying with a resultant increase in carbon. These perverse effects seem to go against the stated aim of the CPS mechanism to achieve low carbon targets and provide stable investment signals.

Due to the significant and far reaching consequences for our business we have devoted substantial resource to this consultation in the limited time available. We regret that the consultation has not been given the recommended twelve weeks especially as it has been issued alongside another major consultation the 'Electricity Market Reform'. However we do welcome the opportunity to share our views on the proposals and would be happy to provide further comment or clarification as necessary.

> "to transform heat losses... it is necessary to promote the greater use of cogeneration and district heating and cooling".
>
> *Energy Efficiency Plan 2011, European Commission communication to Council and European Parliament. Draft published 26th January 2011*

Any questions arising as a result of this response should be addressed to Maureen McCaffrey at maureen.mccaffrey@conocophillips.com

Questions

Investment

3.A1: What are your expectations about the carbon price in 2020 and 2030? And how important a factor will it be when considering investment in low-carbon generation?

ConocoPhillips supports an EU-wide market driven mechanism to deliver a price signal for carbon. Individual companies will have their own view of prices informed by third party data. Company views on forecast price levels cannot be aired or shared for competition reasons. The CPS will interfere with market signals and distort competition in Europe by causing the UK to have a different price for carbon to that of competitors. Section 2.8 of the consultation states that the EUA price has not been 'stable, certain, or high enough to encourage sufficient investment'. The argument is made that CPS is to make up for the failure of the EU ETS to deliver a high and stable price, however it is being applied to some sectors that are not covered by or have different treatment under the EU ETS, such as heat in carbon leakage sectors.

We question the analysis that assumes a future EUA price of £70 per tonne in 2030, as quoted in section 4.4. Should the EUA price be lower than this projection then the CPS will be higher than shown in the base analysis. This will disproportionately affect CHP as CHP will be competing against the alternative rates of CCL on boilers (**See Annex II)** .Hence the higher the rate of CPS, the less favourable CHP will be. Thus this is likely to disincentivise the saving of carbon by CHP generation and encourage the separate generation of heat and power.

3.A2: If investors have greater certainty in the future long-term price of carbon, would this increase investment in low-carbon electricity generation in the UK? If so, please explain why.

Without conditions of certainty, it is much more difficult for investors to predict their costs and returns accurately and therefore the risks underlying any decision will be greater and make it less likely that new investments are pursued. Decisions to invest in low carbon technology will only follow from a certain carbon price if that price suits low carbon investment more than it suits conventional investment. This almost seems too obvious to state and yet we believe that the complex interactions between CPS, CCL and CfD could lead to situations in which the carbon price signal is neutralised. With these interactions in mind, the following are some examples of situations in which a carbon price is more or less effective in driving low carbon investment.

CPS will represent an increased cost and risk for CHP as compared to its competitor technologies. CHP will be exposed to the delta between CPS and boiler CCL on the fuel used to generate heat. CHP will not be able to pass through the cost to its heat customers. CHP heat is often being supplied to industry subject to direct international competition (carbon leakage sectors) which are not exposed to this cost. The heat market is not an open wholesale market where the marginal costs can be passed through. Physics limits the distance of customers and cost will only be borne where the customer can or is willing to absorb them. If the customer alternative is to generate steam from boilers which incur no boiler CCL (in exempt sectors such as refining) or the customer pays limited boiler CCL, due to having entered into CCLAs, or in facilities outside the EU ETS, then the new CPS cannot be passed through. The vast majority of CHP in the UK is in sectors which do not pay or pay limited CCL on boilers. See Annex I.

Annex II Fig's 1-3 highlighting the increased cost to CHP of supplying heat versus standalone boiler generation

The cost of the CPS in electricity can be expected to be passed through to the wholesale electricity market, provided a fossil fuel generator is at the margin. Whilst CHP has a higher thermal (hence overall) efficiency than a CCGT, its electrical efficiency is lower and thus it will not benefit to the same extent as a CCGT from the pass through of the CPS cost for power generation to the wholesale electricity price.

If, as proposed in the Electricity Market Review (EMR), a CfD, or FIT is introduced for all low carbon generation then this generation will become indifferent to the market price of EUAs and CPS, as the revenue received by a low carbon generator under a CfD will be unchanged whether the carbon price is high or low. It is therefore difficult to see how the CPS will have any effect on new low carbon generation under these circumstances.

Existing low carbon generation will benefit from an increase in the carbon price. Renewable generation, if their existing ROCs are grandfathered, will see a windfall benefit from a high carbon price due to higher wholesale prices. Similarly, existing nuclear plant would gain from higher wholesale prices. As these technologies have very low variable costs, they are already at the front of the merit order and therefore generate whenever possible so that no change in operation can be expected to provide additional carbon savings. Hence the only additional carbon savings that we believe could come from CPS (if combined with a CfD) are from coal to gas switching. Some such savings have been shown in the Redpoint modelling but we believe this is as a result of the coal and gas curves used in the projections. The coal curve appears to be unrealistically low when compared to the gas curve and existing market forward curves. Thus coal appears artificially more competitive than it would otherwise be. The analysis therefore exaggerates the amount of coal to gas switching as a result of CPS and hence exaggerates the carbon savings resulting from the measure. Given the LPCD and later the IED much of the older coal plant is in any case curtailed and or retired by 2016 or 2023 respectively.

If CPS is to be introduced without a CfD it would have some effect on low carbon investment, as long as fossil fuel is at the margin. However, using DECC projections, it would appear that increasingly, from 2018, fossil fuel will not always be needed in order to meet demand. When fossil fuel is not at the margin there is no pass through of CPS onto the wholesale price and therefore no benefit to the revenues of low carbon generators as a result of the measures. Thus the window between significant new investment being able to come on stream in response to the measure (circa 2018) and the effectiveness of the measure starting to be diluted, due to no pass through, also from 2018, would seem very short. Redpoint analysis shows that by 2025 fossil fuel is no longer at the margin for the majority of the time. As it is unlikely there will be significant new nuclear until post 2023, the ability of CPS to underwrite new investment appears limited.

It is important that any measure that increases electricity prices particularly to industry is framed to achieve its objectives; otherwise it risks damaging UK competitiveness. We are concerned that CPS will not provide an effective incentive to low carbon generation due to the mismatch of timings. As CPS would be insufficient to generate new low carbon investment without some of the measures contemplated under the EMR, it seems to represent a considerable increase in cost as well as administration and complexity while requiring other additional measures to generate the changes in investment/behaviour required. This seems contrary to the government's simplification agenda. The greater the degree of complexity the more impenetrable the regulations will be for investors seeking to understand the UK market.

As the windfall to existing low carbon generators is likely to be very large this measure would seem to be a poor use of energy bill payer’s money. The cost of this windfall is not quantified in the Redpoint analysis, however using scenario 3 assumptions we have calculated this could be in the order of £850 million per annum by 2020. The cumulative impact of the windfall, for the first 10 years of the mechanism, could be in excess of £5 billion. This calculation excludes windfalls to imported power generators. As importers will be competitively advantaged they are likely to become baseload importers thus 4GW of an average 40 GW of UK demand may be imported and receive further benefit from windfall profits. Government revenue over this period could be in the region of £32 billion. It is therefore not surprising to note that it is the existing owners of nuclear plant in the UK that are the key supporters of this measure, whilst renewable developers appear largely indifferent. (Note the comments of renewable generators to the Climate Change Committee on the 2nd February 2010).

3.A3: How much certainty would investors attribute to a carbon price support mechanism if it were delivered through the tax system?

Any mechanism delivered through the tax system is subject to political risk. The perception of risk from the investment and finance community will lead to any value attributed to the measure being discounted. The greater the perceived risk, the greater the discount that will be applied to it for investment and financing purposes. The level of certainty will also be affected by the general views of the EMR and the overall perceived credibility (hence longevity) of the measures. Investors are already looking at the point at which fossil fuel is not at the margin and thus the point at which CPS ceases to affect the wholesale price.

3.A4: In addition to carbon price support, is further reform of the electricity market necessary to decarbonise the power sector in the UK?

Yes, there are four key areas where we feel that further reform is required:

(1) Management of intermittent supply
The current market design is not likely to lead to sufficient new investment in the UK generation market. Oxera have identified a 17 GW short term supply swing largely as a result of the growth of intermittent wind power. This is the equivalent of all domestic users in the UK going from zero to full power requirement in one hour. The proposals identified by government to date do not identify any measures which will allow the market to manage this level of intermittency, or support the investments in technologies that are needed to compliment the growth of renewables. As well as incentivising low carbon investment, the existing constraints such as grid access, planning constraints and system reinforcement need to be addressed. Failure to deal with these barriers to development is likely to lead to costly over incentives to low carbon generation projects, directing money at the wrong problem. We believe the government has yet to set out a coherent, credible and clear transition plan to the future low carbon state.

(2) Definition of future role for gas
There is a need for a clear narrative from government as to the direction of the electricity market and its interaction with power demand, including heat. In particular, government needs to determine a clear unified message on the future role for gas. Currently government is giving mixed messages as some indicate there is no future role for gas whilst others recognise the need for low cost carbon abatement through gas and the enabling role of gas as a balancing technology to manage the swings in supply which will come with increasing intermittent renewable penetration. It should be noted in particular that neither CCS plant nor nuclear and most renewable technologies are able to easily manage future supply volatility. Gas-fired CHP in particular represents the lowest footprint gas generation and can also be designed to provide flexibility to respond to changes in system supply/demand.

Gas-fired power plant can significantly contribute to the reduction of carbon emissions directly by replacing coal fired plant. Emissions from gas fired CCGTs are lower than equivalent coal fired plant as the carbon content of gas is lower than that of coal and the gas fired power stations are more efficient than coal-fired ones. Typically, carbon emissions from a gas fired CCGT are 60% less than those from a coal fired plant, as well as avoiding the emission of particulates and other gases.

Just as importantly, gas-fired power plant can also indirectly contribute to the reduction in carbon emissions, by supplementing output from renewable sources such as wind which will not always match demand trends. This intermittency of many renewable sources, absent any efficient power storage solution or sufficient demand side response, makes it essential that there is sufficient plant on the grid that can quickly respond to significant changes in renewables-based supply. Gas-fired plant is ideally suited to fulfil this role as their capital cost is several times less than alternatives such as coal and nuclear.

(3) Addressing market liquidity
In order to achieve the very ambitious levels of new investment needed to decarbonise the sector the government needs to maximise access to capital and balance sheet. For new entrants to the UK and for the independent generators the current state of market liquidity presents a barrier and a risk, as imbalances may lead to very high costs, without a portfolio to balance the risk against. So far the measures proposed by government would seem likely to exacerbate the problem rather than improve it. We will expand on this in our response to the EMR consultation.

(4) Effects on the investment in and operation of existing CHP

The question refers to electricity only which ignores the fact that heat is also affected by the proposed measures. 30-50% of EU ETS emissions come from industry. To decarbonise industry, especially those with demand for high grade uninterrupted heat supplies (such as chemical and refining sectors), CHP currently represents the best carbon reduction option, not renewables. CHP can bring the emissions from multiple large plants into a more efficient combined process at a single stack/location that could make future de-carbonisation via renewable fuels or CCS a possibility. It will not be possible for individual boilers to convert to bio-mass due to reliability, sourcing and logistical requirements but a common purpose built CHP may be able to do so in the future.

Administration

4.B1: What changes would you need to make to your procedures and accounting systems to ensure you correctly account for CCL on supplies to electricity generators?

We would have to calculate how much energy is used in the generation of electricity. We would have to accrue for cost of CPS on future sales. We would have to calculate how much refinery off–gas/process gas is used in the generation of energy as this is not a taxable commodity and would thus need to be metered and deducted from other fuels. We would need to account for any distillates used in the generation of energy.

CPUKL is currently not required to be registered for CCL. The introduction of CPS will require it to become CCL registered. We will have to review all affected contracts to identify those liable to CPS. Invoices procedures will need to be amended to charge the correct level of CPS where appropriate. CCL returns will have to be completed and filed.

Alternatively, if the CHPQA and the P11 certificates are used to calculate fuel usage for the generation of heat (as shown in Appendix III) there would be no additional material burden on government or industry when compared to the current proposals. See annex III for a proposal that we believe would resolve a number of issues in relation to CPS being levied against heat generation, primarily un-fairness to CHP.

4.B2: How long would you need to make the necessary changes to your systems to account for CCL on supplies to electricity generators?

There is insufficient definition in the consultation to enable us to answer this question.

4.B3: Please provide an estimate of how much the system changes would cost, both one-off and continuing?

There is insufficient definition in the consultation to enable us to answer this question.

Types of generator

4.C1: Do you agree that all types of electricity generators should be treated equally under the proposed changes? If not, please explain why.

Yes, if CPS is introduced, all types of electricity generation should be charged for fuel used for the generation of electricity. Production of heat (not used for power generation) should not be required to pay as it disincentivises low carbon energy production via CHP. The Cogen Directive and CHPQA programme ensure all Good Quality CHP does deliver carbon savings. Failure to provide such treatment conflicts with policy of the EU on carbon leakage sectors where it is recognised such additional burdens distort international competition and cannot be passed on. It can and will damage the vast majority of industrial CHP. It will have the perverse outcome of disincentivising investments in low carbon generation (CHP), and commensurate lowering of carbon footprint of a facility. The resultant change in operation of existing CHP plant and failure to build new CHP will increase the cost of meeting the UK's carbon objectives.

4.C2: Is there a case for providing additional or more preferential treatment for CHP? If so, what is the best way of achieving this?

We do see a case for providing additional or more preferential treatment for CHP, but recognise that is not the intention of this legislation. However CHP should not be disincentivised as a result of CPS and, contrary to statements in the consultation that would be the consequence of these proposals for the vast majority of CHP installations. **Please see attached in Annex II analysis of the effects of the CPS proposals carried out by the CHPA.**

The question structure implies that the proposals provide preferential treatment for CHP and other stakeholders are likely to respond negatively to this question as a result. You will see from our answer below that this is not the case.

CHP's role in the UK economy and decarbonisation agenda

In 2009, CHP delivered major carbon savings to the UK – estimated at between 9.5 and 13.9 MTCO2. DECC currently project installed capacity of 12.7 GWe by 2020, compared to 5.6 GWe in 2009. Decarbonisation of heat is a major challenge in key sectors of the economy. DECC estimate that industrial CHP can deliver 9.6 MTCO2 savings by 2020 at an economic cost of -£35/tCO2.

CHP is a proven and cost-effective means of carbon abatement and is applicable in a diverse range of applications across the UK economy. It is the only realistic means of significant carbon abatement for many industries particularly those who require very high temperature, high pressure and reliable steam; for instance the Chemicals and Refining sectors. As can be seen from the pie chart **in Annex 1,** much of the large CHP in the UK is focused in these sectors. Industry is the major user and beneficiary of CHP in the UK economy, the majority within carbon leakage sectors. CHP is the most cost-effective, efficient and immediate means of reducing energy usage and subsequent carbon footprint within energy intensive industries such as Refining and Chemicals.

A number of factors prevent wide scale deployment of biomass at industrial facilities, including sustainability and reliability of fuel source given high level of demand required, space and size are additional constraining factors. Most large industrial facilities are in intensive economically developed areas. Logistics, transportation of fuel, waste and air quality all normally make the deployment of biomass at these facilities impossible. Given these factors and the political support for CHP, significant investments have been made in the sector and it remains the best case opportunity to reduce the carbon footprint of many industrial sectors. To the extent bio-methane is added to the gas network, gas-fired CHP will be able to reduce its carbon footprint further.

CHP represents a way to increase security of supply for the UK both by using fuel imports more efficiently but also by being situated near its demand thus increasing security and lowering line losses. Contrary to popular belief, CHP can also be designed to be able to respond quickly to changes in generation supply and thus can complement intermittent wind generation. As CHP used for intensive industry requires constant steam, CHP may hold back electrical capacity and use it to respond to changes in demand very quickly and much more efficiently that other forms of peaking plant and thus compliment a growing intermittent supply of generation from wind. A CHP can also supply more than one industrial host and as much of the UK's energy intensive industry is sited in a few locations; it can often deliver to more than one facility. This means that the emissions from several industrial locations are gathered into a single stack which can allow for either CCS or bio mass at a future date when supply is readily available or the technology proven.

Potential Disincentivisation of CHP

Additional support could be provided to CHP by a full exemption for all certified Good Quality CHP from the CPS mechanism. However, as a minimum, CHP should not be penalised compared to the current situation and this should be done by exempting the fuel used for heat generation from the tax.

The Carbon Floor DECC (2010) document states in section 4.25 that CHP already obtains the following forms of exemption. The list is inaccurate and misleading. ***"Exemptions or Partial exemptions from CCL for the electricity they generate"*** **-** LECs benefit only applies to CHPs that export electricity. As renewable generation also receives LECs and the renewable portfolio is growing rapidly, there are concerns that LEC supply could exceed LEC demand before 2015. This is likely to mean independent CHP generators will not be able to sell their LECs as it can be expected that the large vertically-integrated players (through whom LEC value must be realised) will take the LEC supply from their own portfolios in preference to those of the independent generators and small CHP players. Should LEC supply exceed demand the LEC value for independent generators will tend to zero. ConocoPhillips and the CHPA have shared this analysis with Treasury but will provide a further copy if requested. ***"Ring fenced EUA's for New CHP stations"*** – There is no allocation of EUAs, for electrical generation from 2013, any EUAs for steam go to the heat consumer not the CHP. The customer would also receive EUA (assuming they are of sufficient size) if they were generating on site via less efficient boilers.

"Favourable treatment of small scale CHP under the CRC" – CHP heat is just treated as it would be in a boiler.

"100 per cent first year capital allowance" – Enhanced Capital Allowances are correctly identified as an incentive to some developers if electricity is supplied to known end users and are extremely important in compensating for the increased capital cost of CHPs, but plant must be in a position to generate profit in order to utilise these allowances. ECAs cannot be obtained by those CHPs owned by the large supply companies nor those building CHPs on the government estate. If, as the analysis in Annex II shows, CHP is disadvantaged versus the separate, more carbon intensive, generation of heat and power its ability to operate profitably will be questionable hence ECAs will not lead to a positive investment decision for CHP. Additionally, whilst Enhanced Capital Allowances are currently very helpful in getting positive investment decisions and compensating for the greater capital cost of CHP, once a plant is built they will need to ensure that it continues to operate and it is the operation of a CHP versus the alternative marginal technology that generates the carbon saving. ***"Renewable Obligation Certificates"***, benefit for use of renewable CHP only.

"Business Rate exemption" - This is not an exemption from rates as it applies only to small and embedded CHP and ensures that a plant that converts its boilers to CHP can have them treated as part of the plant for the purposes of rates rather than as a generator. There is no benefit for the vast majority of CHP and no competitive advantage versus CCGT.

The rationale given in section 4.27 of the consultation document for including heat in the Carbon Price mechanism is simplicity, fairness the polluter pays and possible State Aid complications. We will address these separately.

Simplicity – We believe the current proposal is far from simple and conversely throws up a whole host of complications, such as treatment of Partial/Occasional CHP, CHP supplying refinery type installations, treatment of CHP in domestic use, treatment of co-firing, the determination of electricity used in electricity generation and Energy from Waste plant and operators declassifying and reclassifying as CHP (including the plant within the CHPQA boundary which often includes boiler plant). Whereas, the alternative of using the current CHP Quality Assurance (CHPQA) certificate to calculate the amount of fuel used in the generation of good quality heat is simple and would lead to no more material cost or administration for either industry or government. (See Annex III for proposal)

In 4.27 the consultation document states it minded not to treat CHP differently from other generators due to reasons of fairness. The **'Fairness'** criteria do not appear to be met as the proposals penalise CHP and create the perverse outcome that CHP operators may pay government more for making carbon savings.

'Polluter Pays Principle' – Under Phase III of the EUETS CHP does not receive the carbon allocation it goes to the host.

State Aid - we do not believe there are State Aid issues if CHP is treated differently to other types of fossil fuel generation as the Cogen Directive allows for state aid for Good Quality CHP.

Charging CHPs Carbon Price Support on the fuel used to generate heat means that CHP projects will be disadvantaged versus the separate production of power and heat. The vast majority of hosts have CCLAs (hence are 65% exempt from CCL) or are in CCL exempt sectors such as refining and would therefore not be subject to the Carbon Price Support mechanism on CCL for the production of heat in standalone boilers, **See Annex I**. The incentive as currently drafted would mean that one such site that saves carbon by CHP investment (as CHP emits less carbon than the separate production of power and heat), would be paying more 'Carbon tax' than a site that imports power and has standalone boilers. **See Annex II**

There is no relief for CHP from this incremental cost of the CPS on its heat since it cannot be passed through to a heat customer (as plants would not pay CPS on standalone alternative, and heat is not part of a wholesale market). It should also be noted that whilst CHP has a greater thermal efficiency than generation from a CCGT its electrical efficiency is not as high thus it will not benefit to the same extent as a CCGT plant from the pass through of the CPS on to the wholesale electricity price.

CPS will obviously act as a disincentive to investment in new CHP, and it may also affect how existing facilities are run in the future. Some CHP would be incentivised to declassify as CHP (thus increasing actual and reported carbon emissions) or operate differently. For industry that requires very stable high pressure steam, CHP is the most efficient method of doing so available to them. These perverse effects seem to go against the stated aim of the Carbon Price Support Mechanism to achieve low carbon targets and provide stable investment signals.

4.C3: Do you agree that tax relief should be considered for power stations with CCS? If so, what are the practical issues in designing a relief; what operational standards should a CCS plant meet in order to be eligible; and how might these issues differ for demonstration projects?

Yes as the concept of CPS is the payment related to final emissions. The relief should be aligned with the Monitoring Reporting and Verification requirements of the EU ETS.

We do not believe the CCS timetable outlined in the Redpoint Analysis is credible; there is no prospect of two 300 MW plant being up and running by 2015 and four by 2018. We also do not believe the modelled retrofitting of all existing plant with CCS by 2025 is possible due to supply chain and labour availability. Relief should only apply to the proportion of the facility which has CCS and based on abated carbon. CCS CHP will have lower carbon for useful energy delivered so should benefit proportionally.

Imports and exports

4.D1: What impact would the Government's proposals have on electricity generators and suppliers that export or import electricity?

The Government's proposals are likely to introduce further market distortion which will increase the import of electricity to the UK. Imports are already advantaged as they do not pay TNUoS. By 2013, 4 GW of Interconnection (excluding a proposed link to the Norwegian system) can be expected (2 GW French, 1 GW Irish, 1 GW BritNed). The total 4 GW of interconnection can expect to be fully utilised, as it is at a commercial advantage to UK power, this represents 10% of the average UK demand of around 40GW. This effectively creates additional 10% base load power in the UK hence increased pressure to provide a higher proportion of flexible generation in the UK. The Government has not attached sufficient significance to this in its impact assessment. We would prefer to have an EU-wide mechanism to support the carbon price, which would create a level playing field for electricity generation and supply and reduce competitive distortions at least within Europe. We note that the European Commission may bring forward proposals in the first half of 2011 for an EU-wide carbon tax. There will also be an issue around the export of electricity as increased wholesale prices in the UK resulting from CPS will mean that higher prices may be exported to the continent or UK exports become uncompetitive.
The EU is currently raising the profile of the need for greater transmission between EU states. Analysis has shown that this is an important factor in managing the increasing intermittency of renewable power sources. Having a unilateral UK carbon price would seem to fly in the face of this policy by distorting the cost of generating between member states.

Power imported from these sources may not be low carbon as trading may encourage use of high carbon power generation. French nuclear for example is already base load so it will be the marginal continental plants that will be encouraged to run. These unintended consequences provide windfall to owners and capacity holders of interconnectors as well as a disproportionate advantage for overseas generation.

4.D2: What impact might the proposals have on trading arrangements for electricity?

The severity of the impact of the proposals on electricity trading arrangements will depend largely on the way in which they are introduced. To avoid market shocks, the method and timing of setting the tax should be visible to operators well in advance of its introduction, be as predictable as possible and be aligned with market arrangements. A lack of predictability would tend to reduce hedging through forward sales of electricity and thereby further reducing the already inadequate levels of market liquidity. Some delay in the introduction of the tax would help the industry to work through existing/legacy contracts.

4.D3: What impact might the proposals have on electricity generation, trading and supply in the single electricity market in Northern Ireland and Ireland?

In addition to the answers given to 4.D1

It is unclear how CPS would interact with SEM and this is not addressed in the consultation document, but prices in the Irish Republic could be expected to increase as generators in the North of Ireland will incur the additional cost which will be passed through via the all Ireland market and the SEM mechanism.

Carbon price support mechanism

4.E1: How should the carbon price support rates be set in order to increase certainty for investors, in particular over the medium and long term?

CPS will provide little certainty for investment due to the political and unilateral nature of the measure and the fact that its effect diminishes with increasing low carbon penetration, expected to be from 2018.

It may create uncertainty if it is introduced quickly due to hedging and trading activity. Government need to ensure the traded power and EUA market are healthy and liquid in order to ensure no damage is done.

4.E2: Which mechanism, or alternative approach, would you most support and why?

For the reasons above, we believe that CPS will add to the cost of electricity with little material benefit in terms of low carbon generation. It is unclear what the value of CPS will be within the context of wider reforms. In the interest of simplification for both Government and industry, we would prefer for all low carbon incentives for low carbon generation to be explicit through one mechanism to ensure transparency.

Section 4.39 of the consultation document sets out three possible options:

- A **rate escalator** set at levels to achieve a specific carbon price trajectory over the life of a Parliament consistent with an overall target for the carbon price in 2020;
- **Annually adjusted CCL rates and fuel duty rebates** that take account of short-term trends in the carbon market and economy to ensure closer targeting of the Government's carbon price trajectory from year to year;
- **Rates set annually based on a carbon market index** averaged over a specific annual or biennial period to reflect future carbon prices.

We do not favour either the 'escalator' or 'annually adjusted rate'. Our preference is for rates set annually based on the carbon market index.

The stated intent of the proposal is to provide greater stability and certainty over the carbon price. The only method of achieving this is through a mechanism which explicitly links the support rate and the emissions price achieved in the market. By setting the rate over an annual index the government avoid setting a rate in a manner which lacks transparency or which is tied to the price at one point in time. Rather than allowing different companies to hedge using a timing of their choice, any mechanism will force a large number of buyers onto the market at a known time and could potentially distort the market. Although this will be a natural consequence of any support mechanism linked to the market price, the longer the time period over which the index is set the less the market will be impacted.

Ideally the rate should be tied to an emissions price at or close to the time of delivery. This avoids tying up capital holding EUAs for long periods of time and achieves closer matches with the EUAs purchased at the index to the number of EUAs required by a generator. One method could be setting the support rate monthly based on the average index for the previous month. We assume that the UK EUA auctions will be the index used to set the reference price. As such, auctions should be held on a regular (e.g. weekly) basis rather than the current irregular sales of large volumes to tie purchases closer to time of delivery of power.

4.E3: What impact would the proposals have on your carbon trading arrangements?

The proposal will significantly impact hedging strategies for all companies impacted by the Carbon Price Support rate. As the support rate is relative to a defined EU ETS price, to maintain certainty over carbon price achieved it will be necessary to source credits at the time the price is defined. To source credits at any time before or after the price is defined would create uncertainty over the total price achieved, as the total carbon price will be EUA price plus carbon support price.

Additionally, the price support mechanism may impact the instruments used to hedge carbon, adding extra cost to generators. Generators may need to use options or similar to hedge the risk from shifts in the carbon price from below to above the support price level (or vice versa).

The impact would therefore be twofold. As well as increasing the complexity of the instruments required to hedge our own carbon requirement we are concerned that the proposal could have a negative impact on the already illiquid forward curve due to the additional risk it introduces to all market participants. Generators who currently start hedging three years forward may bring their hedging programme closer to the period of delivery, removing this volume from the market. Whereas previously a generator could lock in a clean spark (or dark) spread through purchasing carbon and gas (or coal) and selling the power, purchasing carbon at the same time as the fuel and power legs under a CPS mechanism would actually be a view on carbon price (speculation) rather than a hedge.

The CPS introduces risk to generators due to it being a one-way payment, in that generators will pay if the carbon reference price is less than the support rate target, but receive no payment if the carbon reference price is more than the support rate target. The risk to generator hedging comes from volatility over time, the greater the time difference between the fuel and power hedges the more likely the market price for carbon would switch from under to over the reference price (or vice versa). Even if the market price at the time of entering hedges was above the target price level, hence the CPS rate would be set at 0, it would still be impossible to hedge carbon without taking a price view due to the possibility of subsequent declines in market price. This decline would lead to a CPS rate greater than 0 and therefore an increased total carbon cost. However, by not hedging carbon, the generator is left open to further price increases eroding the margin they hedged. The risk of this price movement leads to uncertainty over the total effective carbon price applicable at the time of entering into generation hedges and so an increase in the risk premium included in market prices and a reduction in the number of parties prepared to take this risk.

Future price of carbon

4.F1: Should the Government target a certain carbon price a) for 2020 and b) for 2030? If so, at what level?

It is much easier to determine a desired emissions level than a desired price. That was the rational of cap and trade versus a tax. If the government wants to set new or different emissions levels or standards that is a different matter and can be much more accurately targeted than a price signal which, as discussed elsewhere in this response, is obfuscated by other interacting measures.

If a carbon price support mechanism is to be introduced, the Government should target a certain carbon price for 2020. Given the lack of visibility of the emissions reduction trajectory in the EUETS post-2020 and the political uncertainty surrounding EU emission reduction targets for 2020, it will be challenging to target a price for 2030 at this stage.

For CHP, the target price is less relevant than the difference between the EUA price and the target as this represents the level of CPS. As EUA price is an unknown, the target price is irrelevant. The reason the absolute number is important to CHP is that it is this number that will be compared with the counterfactual investment cost (or lack thereof) for those with CCL exemption on boilers (such as refining) and for those with CCAs, who are partially exempt from CCL on boilers as this represents the costs applied for separate generation of heat when compared to that for CHP heat. Lack of predictability of CPS represents a risk to CHP thus discouraging investment and increasing hurdle rates on investment decisions. For power generation, the same does not apply as the addition of EUA and CPS can be assumed to equate to the target price irrespective of the split between the two.

4.F2: What is the most appropriate carbon price for the UK to meet its emissions reduction targets in the power generation sector? How would this be affected by changes in the structure of the electricity market?

We do not believe the CPS target price will be the key driver for new investments and that it is the CFD (or FIT) mechanism under the EMR that will provide the key investment drivers. The target price could however be detrimental to investment in and operation of CHP to the extent the target price differs from the EUA price. This difference represents the CPS against which the rate paid by boilers is compared. As is shown in the CHPA analysis (**see Annex II**) the higher the CPS the greater the disincentive to CHP.

4.F3: When would be the most appropriate time for introducing a carbon price support mechanism and what would be the most appropriate level?

The level of carbon price support should be notional until 2018 at the earliest.

Electricity investment

5.B1: What impact would you expect the carbon price support mechanism to have on investment in low-carbon electricity generation?

We expect investment in low-carbon electricity to be driven predominantly by the measures introduced as part of the broader EMR package (CfDs or FITs). As currently proposed, the mechanism would disincentivise new investment in CHP and may lead existing CHP to de-classify with a resulting increase in emissions. We do not believe that there will be much coal to gas switching as a result of the measure as coal is normally at the back of the merit order and the coal cost curve used in the Redpoint analysis is too low relative to the gas curve thus overstating the savings. Existing renewables will not change their place in the merit order and output is non-price responsive. The exact effects will depend on which support mechanism is chosen as part of the EMR.

- New low carbon investment will be indifferent to wholesale prices if a CfD is introduced and will not therefore benefit from any increase in prices.
- If a Premium FIT is introduced then new low carbon investment would benefit from the increase in wholesale price bought about by CPS but only to the extent fossil fuel is at the margin. Using government projections, we see that is not always the case from as soon as 2018 and Redpoint state it is not the case the majority of the time from 2025.

As significant new nuclear investments cannot be on stream until 2023, the benefit that will be attributed to it in their investment economics would seem to be minimal. There will however be substantial windfall benefits for existing low carbon generation but we do not see this having any effect on the output from those facilities as they are already at the front of the merit order (base load).

5.B2: What other impacts would you expect carbon price support to have on investment decisions in the electricity market?

Carbon price support is likely to affect investment decisions for projects that are not subject to the “contract for difference” (or FIT) model under EMR. It will also affect investment decisions for existing coal and gas-fired power stations that will be subject to the requirements of the Industrial Emissions Directive in the period post-2015. Those stations are expected to make an important contribution to the security of electricity supply during the transition to a low-carbon generating fleet.
The CPS treatment of heat will prevent new investment in CHP, reduce the despatch of existing CHPs and may lead to some CHPs declassifying.

5.B3: How should carbon price support be structured to support investment in electricity generation whilst limiting impacts on the wholesale electricity price?

We are unclear as to the intent of this question. If CPS does not affect the wholesale price, it would not be of any benefit to low carbon generation.

The support mechanism should be introduced in a way that minimises disruption of the existing electricity market arrangements. Introducing a notional rate of CPS for the period to 2018 would help to achieve that.

Existing low-carbon generators

5.C1: Can you provide an assessment of the impact of the proposals on your generation portfolio and overall profitability?

For impact on fossil fuel CHP sector please see analysis in Annex II.

Our investment in the Immingham CHP would be undermined as the CHP would face significant additional carbon taxes versus the separate generation of heat from boilers on the ConocoPhillips Humber and Total Lindsey oil refineries.

We are currently looking to develop an 800 MW CHP at Teesside; It would be very unlikely this investment could proceed if the CPS is implemented as drafted.

5.C2: What would be the implications of supporting the carbon price for existing electricity generators and how should the Government take this into account?

It will impact investment decisions including plant retirements. It will disincentivise CHP, leading to a fall in CHP output and a commensurate increase in carbon.

Electricity price impacts

5.D1: How do you currently manage fluctuations in the wholesale electricity price?

We cannot address this for reasons of commercial confidentiality and competition law.

5.D2: What difference will supporting the carbon price make to your business?

As drafted it will disincentivise future CHP developments and our existing CHP will be made less economic which could be expected to lead to reduced load factors going forward. It will also make further investment by our company in new CHP projects in the UK unlikely.

5.D3: As an electricity generator or supplier, how much of the cost of the carbon price support would you pass on to consumers?

To the extent the electricity price is increased due to the pass through of CPS on to the wholesale price, we would obtain a higher wholesale price. Higher costs cannot be passed through to heat customers who would not otherwise incur those costs were they to generate their own heat from boilers. As ConocoPhillips operates in the refining sector, this is the case for our host customers.

5.D4: As a business, how much of the cost of energy bills do you pass on to customers?

See answer to 5D3
In addition, refined products compete in markets based on global pricing. Additional costs which are not incurred by competitors are highly unlikely to be passed on (and if they are the competitors still have a profitability advantage), and rises in electricity prices caused by this CPS, and CRC additionally, will tend to decrease the output of UK refineries and increase imports.

5.D5: How might your company or sector be affected and would be there any impact on your profit margins?

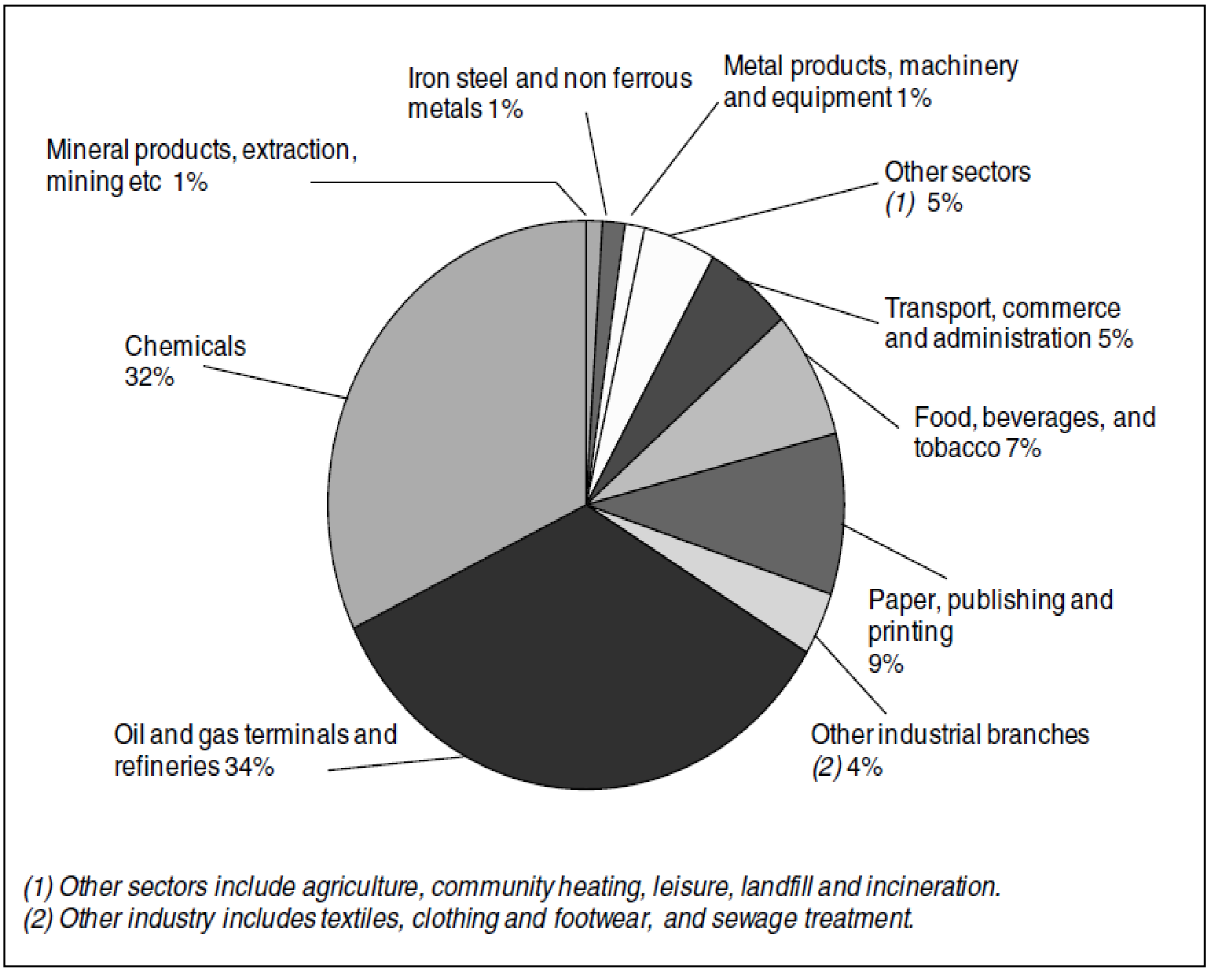
The Government's proposals are likely to introduce a market distortion which will increase the import of electricity to the UK. Our company and sector (CHP) would be adversely affected. Confidence in the UK markets and future investment in the power market would be undermined.

At the levels suggested in the consultation, by 2030 UK industry might be paying carbon costs in electricity prices several times greater than even the rest of Europe, when CPS and CRC are taken together. In many industries this will be sufficient to produce a significant impetus for imports. It is essential that the total impact of climate change measures on costs is clearly assessed.

5.D6: Do you have any comments on the assessment of equality and other impacts in the evidence base of the Impact Assessment, included at Annex D?

The Coal Forward Curve used by Redpoint in modelling appears to be unrealistically low pushing coal higher up the merit order than currently positioned and leading to likely overstatement of benefits in relation to carbon savings. The Impact Assessment states there will be no impact to competition, however the analysis in annex II highlights CHP will be disadvantaged versus it's competition. The Carbon Leakage and competitiveness section does not identify the refining sector or the impact of taxing heat.

Annex 1 - DECC 2010 CHP by sector



Source, Digest of UK Energy Statistics (DUKES)

Annex II

This CHPA analysis modelled the impact of the proposed CPS on 3 sample types of CHP plant versus the comparative investment decision of separate generation of Power and Heat.

- Large CHP generating 830MW of Power, supplying 300 teph of Steam to a Refinery.
- Medium CHP generating 66MW of Power, supplying 95 teph of Steam to a user with a CCLA.
- Small embedded CHP generating 1MW of Power and 2 teph of Steam.

N.B Input assumptions for this modelling have been based on independent government endorsed sources wherever possible. All fuel and commodity pricing assumptions are DECCs central case, carbon price scenarios are as per HMT, cost assumption are from Mott MacDonald and generation output assumptions are based on DUKES.

The following charts highlight the increased liability faced by CHP versus separate generation and prove that the statement made in 4.26 of the consultation document, namely “Fossil fuel based CHP would still face a significantly lower CCL liability relative to the separate generation of heat and power” is incorrect.

The three charts below show that under CPS the generation of Heat in a CHP will face a greater liability than that from comparative generation in a standalone boiler.

Figure 1 – The impact of the CPS is that a large CHP supplying heat to a refinery will face a greater liability than that of a boiler which faces a zero liability.

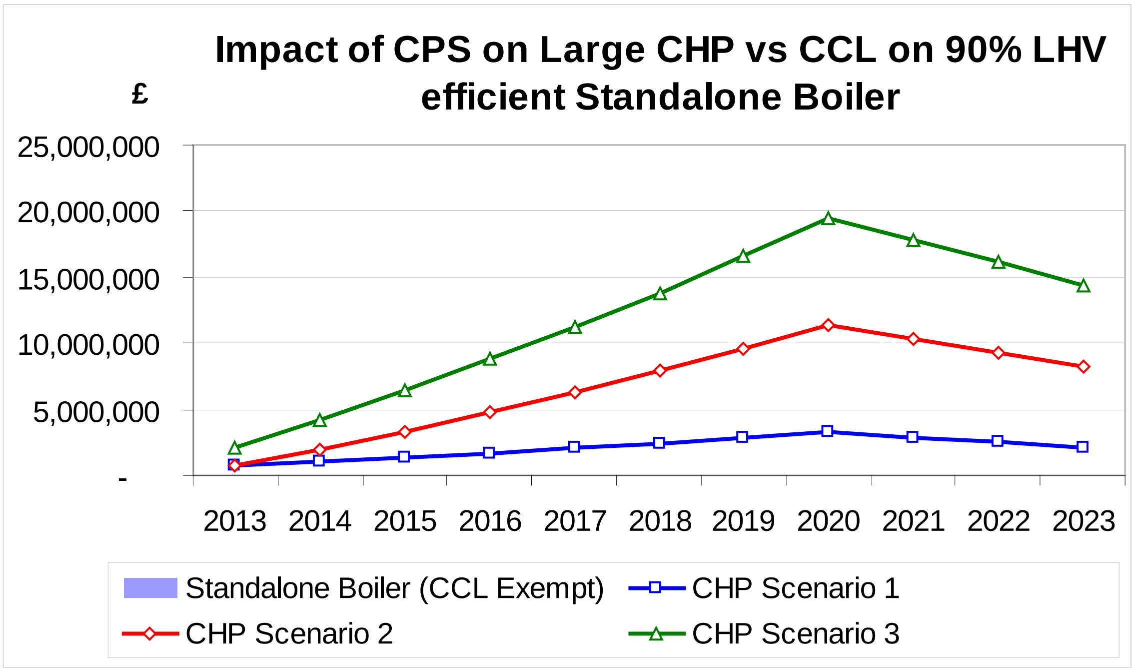


Figure 2 – The impact of the CPS is that a Medium sized CHP supplying heat to a user with a CCLA will face a greater liability than that of a boiler which receives a 65% CCL discount under most scenarios.

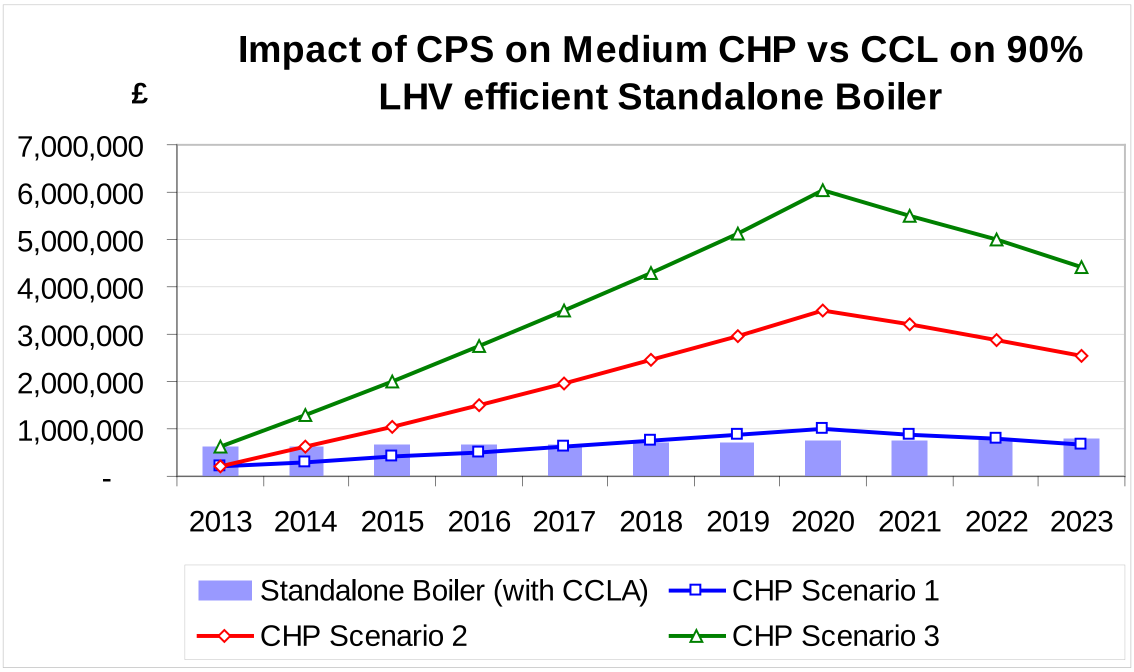
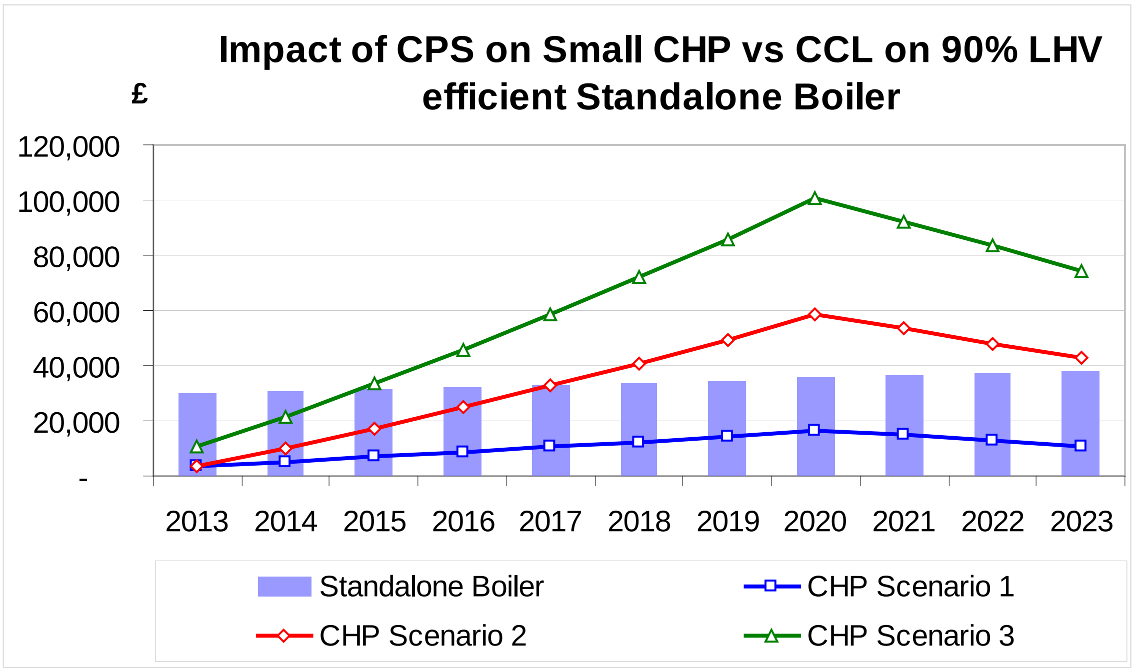


Figure 3 – The impact of the CPS is that a Small sized CHP supplying heat to a user will face a greater liability than that of a boiler under Scenarios 2 and 3 for most of the time



The next 3 charts show that when the lines cross above the zero point on the y-axis, the total liability to CHP is greater than that of separate generation and result in CHP paying government for saving emissions.

For the Large CHP this occurs under all scenarios from implementation. For Medium CHP this occurs under scenario 2 from 2016 and under scenario 3 from 2014. For the Small CHP this occurs only under scenario 3 from 2018.

Figure 4

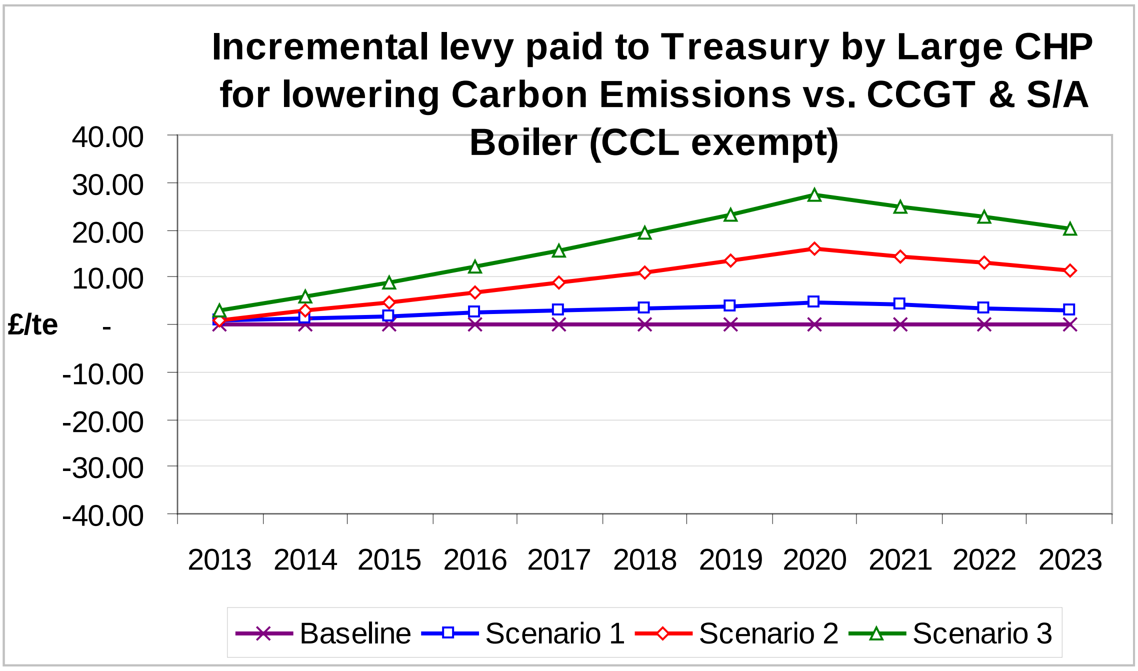


Figure 5

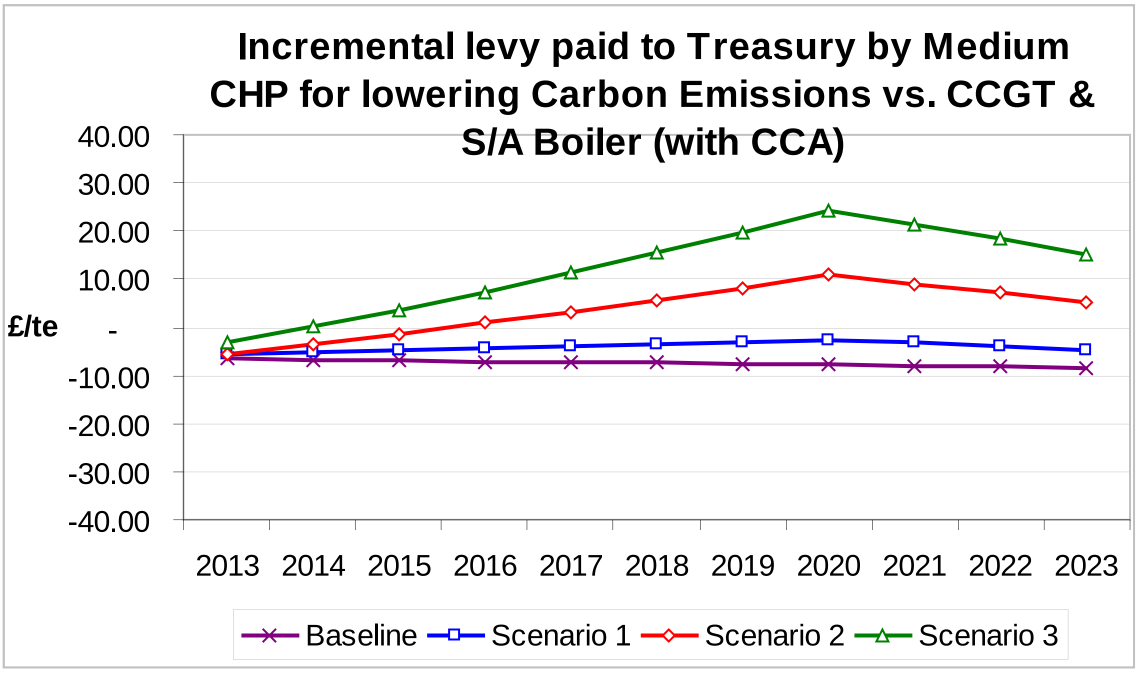
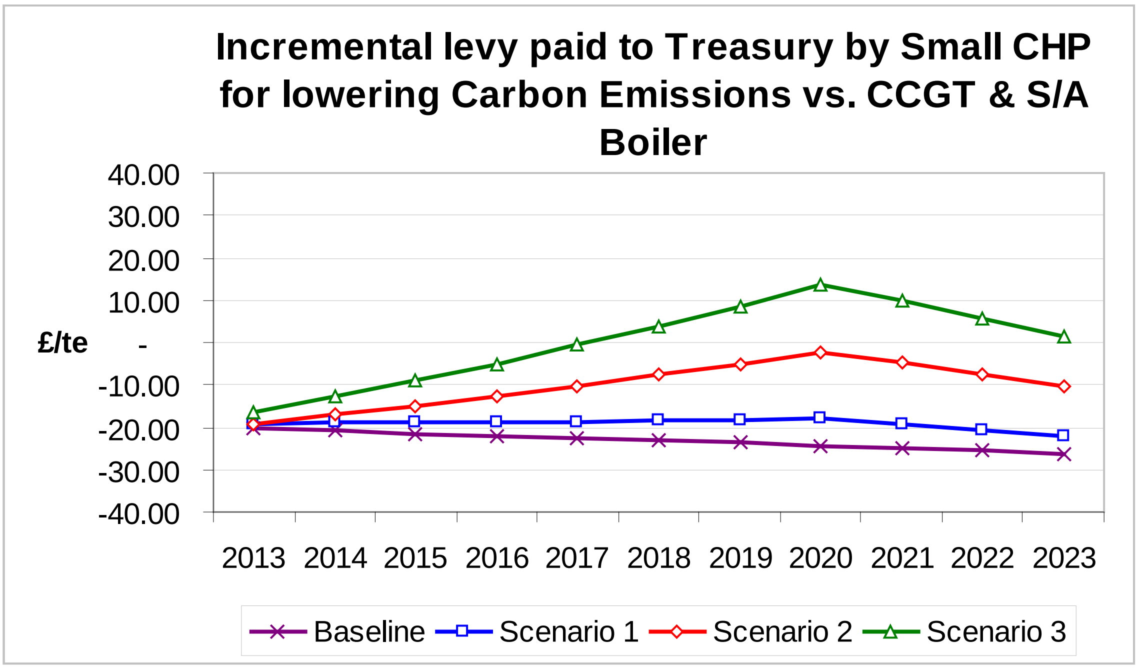


Figure 6



The tables below highlight the impact on IRR from CPS to CHP and its competition (Fig.7) and that by exempting heat CHP can move back to a position of equilibrium (Fig 8), annex III proposes how this could by achieved simply.

Figure 7

IRR Impact vs. Baseline	**CPS on all fuel inputs**		
Plant Type	**Scenario 1**	**Scenario 2**	**Scenario 3**
Large CHP	-0.8%	-2.7%	-4.5%
Large CCGT + Boiler (CCL exempt)	-0.6%	-1.9%	-3.3%
Medium CHP	-1.1%	-3.6%	-6.2%
Medium CCGT + Boiler (with CCA)	-0.5%	-1.7%	-2.9%
Small CHP	-0.8%	-2.9%	-5.0%
Small CCGT + Boiler	-0.5%	-1.7%	-2.9%

Figure 8

IRR Impact vs. Baseline	**CPS on fuel inputs (heat exempted)**		
Plant Type	**Scenario 1**	**Scenario 2**	**Scenario 3**
Large CHP	-0.7%	-2.1%	-3.6%
Large CCGT + Boiler (CCL exempt)	-0.6%	-1.9%	-3.3%
Medium CHP	-0.4%	-1.4%	-2.4%
Medium CCGT + Boiler (with CCA)	-0.5%	-1.7%	-2.9%
Small CHP	-0.3%	-1.0%	-1.7%
Small CCGT + Boiler	-0.5%	-1.7%	-2.9%

NB. All analysis and modelling is attributable to the CHPA.

Annex III

As ConocoPhillips state in response to the consultation, and the CHPA modelling shows in Annex II, we believe that CHP should be exempted from the fuel it uses to generate heat in order to retain its current competitive position versus the separate generation of heat and power. This can be achieved by a simple calculation using the existing CHPQA process building on a process that is already in place and familiar to suppliers, with no additional material cost or administrative burden to both government and industry.

The CHPQA calculation already identifies Qualifying Heat Output (QHO), Total Fuel Inputs (TFI) and Qualifying Fuel Inputs (QFI). Assuming that the operator qualifies as 100% Good Quality CHP, QFI and TFI are the same number. Taking QHO and dividing by the efficiency delivered from a standalone boiler 85% HHV would give Fuel used in the generation of heat, which would then be deducted from QFI to ascertain the fuel inputs subject to CPS. See example I below

Example 1

TFI	100MW
QFI	100MW
QHO	30MW

Fuel used in the generation of Heat (HFI) = QHO / Standalone Boiler Efficiency

HFI = 30 / 0.85
HFI = 35MW

TFI subject to CPS = QFI – HFI
TFI subject to CPS = 100 – 35
TFI subject to CPS = 65MW

If the CHP operator is partially qualified then QFI would be lower than TFI the calculation would be as per example II below

Example II

TFI	100MW
QFI	80MW
QHO	20MW

HFI = 20 / 0.85
HFI = 24MW

TFI subject to CPS = QFI – HFI + TFI – QFI
TFI subject to CPS = 80 – 24 + 100 - 80
TFI subject to CPS = 76MW

A simple amendment to the CHPQA certificate could identify the volume calculated above and the PP11 CCL exemption form could be amended to provide the supplier with the proportion of input fuel subject to CPS chp QA

DEPARTMENT OF ENERGY & CLIMATE CHANGE

Quality Certification for an existing CHP Scheme

CHPQA Certificate No: **P03221799**

Scheme:

CHPQA Scheme Reference No: **739 B**
This is to Certifv that the Self-Assessment of the above CHP Scheme undertaken by

of Scheme performance during the calendar year: **2009** has been Validated under the Combined Heat and Power Quality Assurance programme and that:

1. The Total Power Capacity of this Scheme is:	MV
and the **Qualifying Power Capacity** is:	MV
2. The threshold Power Efficiency criterion for this Scheme is:	**20** %
and the **Power Efficiency** of this Scheme is:	%
3. The Qualifying Heat Output from this Scheme is:	MV
and the **Heat Efficiency** of this Scheme is:	%
4. The threshold Quality Index criterion for this Scheme under **Annual Operation** is:	**100**
and the **Quality Index** of this Scheme is:	
5. The Total Fuel Input to this Scheme is:	MV
and the **Qualifying Fuel Input** is:	MV
6. The Total Fuel Input used in Heat generation to this Scheme is:	MV
and the Qualifying Fuel Input Subject to Carbon Price Support is:	MV
7. The Total Power Output from this Scheme is:	MW
and the Qualifying Power Output is:	MW

8. The fuel supply reference(s) (e.g. TRANSCO/MPR gas meter reference nos. And/or other unique ID descriptors) for this scheme are:

This certificate is a statement of Scheme performance over the period 01/01/2009 to 31/12/2009 and is valid until 31/12/2010

Approved by the CHPQA Administrator on behalf of DECC. Date: ***11 MAY 2010***

The CHPQA programme is carried out on behalf of the Department of Energy and Climate Change (DECC), in consultation with the Scottish Executive, The National Assembly for Wales, and the Northern Ireland Department of Enterprise, Trade and Investment

For the purposes of the Climate Change Levy (General) (Amendment) Regulations 2003 only, the QPO limit shall be equal to the actual output of the station multiplied by the following ratio: the Qualifying Power Output referred to at item 6 above over the Total Power Output referred to at item 6 above.